BANFF/2001 PIPELINE WORKSHOP

Managing Pipeline Integrity
A Workshop for Sharing Technology and Experience

April 9-12, 2001

Tutorials: April 9, 2001

Banff Centre for Conferences
Banff, Alberta, Canada

Proceedings

http://www.nrcan.gc.ca/mms/canmet-mtb/mtl/banff2001/default.htm

In-line Inspection

Bruce Nestleroth, Battelle and Pat Vieth, CC Technology

The in-line inspection tutorial was attended by over 50 workshop registrants and was a mix of pipeline company experts with years of experience with in-line inspection, pipeline company neophytes, inspection vendors, consultants and government regulators. The afternoon portion added about 20 additional workshop registrants from the morning corrosion assessment workshop. Bruce Nestleroth led the morning session, which covered the technical aspects of in-line inspection. After a brief introduction to terms used on all types of in-line inspection tools, the workshop focused on the most commonly used technology, magnetic flux leakage (MFL). This included both the widely used technology that magnetizes in the axial direction, and the emerging technology that magnetizes in the circumferenial direction, transverse to the axial direction.

The MFL tutorial started with application of the magnetic field and the inspection variables that effect the results including velocity, pipe material, wall thickness, diameter and remanent magnetization. Then characteristics of flux leakage from pipeline defects was discussed. Examples from defects recorded using the GTI Pipeline Simulation Facility MFL Test Pig were shown along with the effect of inspection variables. Sensor and data recording considerations were discussed. Finally a performance capability prognosis was given.

To compliment the theory of in-line inspection, the two applications of pigging was presented by Pat Vieth. The first was corrosion example and the use of assessment criteria such as RSTRGTH and B31G. Concepts of prioritization and dealing with the uncertainties of in-line inspection were presented. The second was a seam weld defect example using transverse (circumferential) MFL technology. Detection of hook cracks, lack of fusion and other defects were presented. Since all defects detected with this technology and removed from service passed hydrostatic testing, the pipeline was confidently returned to service.

Attendees at In-Line Inspection Tutorial – April 9, 2001 9:00 a.m. - noon Session

1.	Chris Horkoff	AEC Oil & Gas	Medicine Hat, AB
2.	Chris Grant	Alberta Energy and Utilities Board	Calgary, AB
3.	Arti Bhatia	Alliance Pipeline	Calgary, AB
4.	Daryll Wendland	Alliance Pipeline Ltd.	Grande Prairie, AB
5.	Terri Johnston	Alliance Pipeline Ltd.	Calgary, AB
6.	Ben Sokol	ATCO Pipelines	Edmonton, AB
7.	Fred Baines	BC Gas Utility Ltd.	Surrey, BC
8.	Chris Billinton	BC Gas Utility Ltd.	Kelowna, BC
9.	Chris Hallam	BJ Pipeline Inspection	Calgary, AB
10.	Jenny Been	CANMET	Ottawa, ON
11.	Bill Tyson	CANMET Materials Technology Lab	Ottawa, ON
12.	Alebachew Demoz	CANMET Western Research Centre	Devon, AB
13.	Cliff Mitchell	CJ Mitchell & Associates Ltd.	Calgary, AB
14.	Dave Webster	Colt Engineering Corporation	Calgary, AB
15.	Chris Pollard	Cornerstone Pipeline Inspection Group	Houston, TX
16.	Zane Reinhart	Corrpro Canada Inc.	Calgary, AB
17.	Grant Firth	Corrpro Canada Inc.	Calgary, AB
18.	Doug Doran	Corrpro Canada Inc.	Calgary, AB
19.	Don Engen	Enbridge Pipelines Inc.	Edmonton, AB
20.	Shawn Dawe	Enbridge Pipelines Inc.	Edmonton, AB
21.	Garrett Hilkie	Enbridge Pipelines Inc.	Edmonton, AB
22.	Mo Mohitpoul	Enbridge Pipelines Inc.	Edmonton, AB
23.	Blair Carroll	Fleet Technology Ltd.	Edmonton, AB
24.	Kyle Keith	Foothills Pipe Lines Ltd.	Calgary, AB
25.	John Chase	Hunter McDonnell Pipeline Services	Edmonton, AB
26.	Debbie Siemens	Hunter McDonnell Pipeline Services	Edmonton, AB
27.	Al Forth	Imperial Oil, Pipeline Operations	Waterdown, ON
28.	Neil S. Hay	Koch Pipelines Canada L.P.	Calgary, AB
29.	Bruno Romero	Maya Database & Internet Apps. Inc.	Calgary, AB
30.	Dennis Hinnah	Minerals Management Service	Anchorage, AK
31.	Tom Morrison	Morrison Scientific Inc.	Calgary, AB
32.	Rima Raed	National Energy Board	Calgary, AB
33.	Josef Kopec	National Energy Board	Calgary, AB
34.	Paul Trudel	National Energy Board	Calgary, AB
35.	Mary Gale	Nova Chemicals	Red Deer, AB
36.	Ray Jones	Nova Chemicals	Red Deer, AB
37.	Pete Donnelly	Pembina Pipeline Corporation	Drayton Valley, AB
38.	Chris Pierce	Pierce Consulting Ltd.	Calgary, AB
39.	Lee Greanyp	Positive Projects International Ltd.	Calgary, AB
40.	Ivani De S. Bott	Puc-Rio/DCMM	Rio de Janeiro, Brazil
41.	Rick Stelmachuk	Rosen Inpsection Technologies	Houston, TX
42.	Jim Yukes	Russell NDE Systems	Edmonton, AB
43.	Dave Toporowsky	Simmons Group Inc.	Calgary, AB
44.	Brian Dennis	Suncor Energy Marketing Inc.	Sherwood Park, AB
45.	Gabriel Nahas	TransCanada (Ventures Projects)	Calgary, AB
46.	Greg Toth	TransMountain Pipeline	Vancouver, BC
47.	J.P. McNeice	TransMountain Pipeline	Kamloops, BC
48.	Tom Weber	Trenton Corporation	Houston, TX
49.	Lance Bengert	Westcoast Energy	
50.	Gord Gairdner	Westcoast Energy	Fort Nelson, BC

Risk Management / Risk Analysis Tutorial

Presented by Ian Dowsett, RWDI West Inc.

Increasing pipeline infrastructure coupled with a growing and knowledgeable public located near pipelines is resulting in increased public concern about pipelines. These concerns include public safety, health, the environment, quality-of-life and the distribution of the risks and benefits from pipeline activities.

The Risk Management / Risk Analysis tutorial addressed many of the factors underlying "Public Safety" decisions (both technical and non-technical). The tutorial presented:

- An overview of the views, roles and responsibilities of industry and the regulators.
- The views and influences that the public has in effecting energy development decisions.
- An example (through the use of a video) of public involvement and influence on a recent energy development decision.
- A summary of the technical tools used to estimate hazards and risks.

The tutorial provided an interactive setting. Attendees indicated that:

- The public's view of hazards and risks is very different than the view held by industry.
- Standardization of the methods used for calculating hazard and risks would provide more consistent estimates of hazards and risks and would minimize uncertainty resulting from differences in the opinions expressed by experts.
- There is a need to differentiate between "the hazard" (i.e., worst case scenario) and "the risk" (i.e., the probability of being affected), and to differentiate between the decisions and their priority (i.e., public safety, health, and environment).
- There is a need for risk acceptability criteria.
- There is a need to improve the communication of all of these issues to the public and industry itself.

Attendees at Risk Assessment/Risk Management Tutorial – April 9, 2001

1.	George Prociw	Enbridge Consumers Gas	Scarborough, ON
2.	Lawrence Ator	National Energy Board	Calgary
3.	Nathan Len	National Energy Board	Calgary
4.	Nancy Dubois	National Energy Board	Calgary
5.	Rick Gulstad	Alliance Pipeline	Eden Prairie, MB
6.	Allan Bouwers	NeoCorr Engineering Ltd.	Calgary
7.	Bob Longpre	BP Canada Energy Company	Calgary
8.	Daryl Baxandall	CorrOcean Canada Inc.	Calgary
9.	David Coleman	Centra Gas Manitoba	Winnipeg, MB
10.	Leonard Lozowy	AltaGas Utilities	Leduc, AB
11.	Aldo Diflumeri	Canadian Natural Resources Ltd.	Calgary
12.	Bob Shapka	Talisman Energy	Calgary
13.	Andy Isherwood	BGC Engineering	
14.	Denene Geissler	Hunter McDonnell Pipeline Services	Edmonton
15.	Siu-Yung Tsai	TransCanada Pipelines Ltd.	Redcliff, AB
16.	Lorance Pasiechnyk	Simmons Group Inc. – Pipelines	Calgary
17.	Lyle Gerlitz	FLG Engineering Ltd.	Calgary
18.	Steve Lambert	University of Waterloo	Waterloo, ON
19.	Duane Cronin	University of Waterloo	Waterloo, ON
20.	Roy Pick	University of Waterloo	Waterloo, ON
21.	Norm Trusler	BC Gas Utility	Surrey, BC
22.	Bruce Fowlie	Nu-Trac Management Consulting Ltd.	Calgary
23.	Paola Bonandrini	SNAM s.p.A.	Italy
24.	Bruno Romero	Maya Database & Internet Applications Inc.	Calgary
25.	Bob Wiens	Oesa Associates	
26.	Ken Poloway	Mobiltex Data Ltd.	Calgary
27.	Rob Slevin	Mobiltex Data Ltd.	Calgary
28.	Daphne Snelgrove	Transportation Safety Board	Hull, PQ
29.	David Don	HCI Canada	Calgary
30.	Larry Dyke	Natural Resources Canada	Ottawa
31.	Cindy Smallman		
32.	Lin Zharo	ABS	
33.	Ramesh Singh	RAI Inspection Service	Edmonton
34.	Noel Billette	Natural Resources Canada	Ottawa, ON
35.	Wenyue Zheng	Natural Resources Canada	Ottawa, ON
36.	Jenny Jackman	CANMET	Ottawa, ON
37.	Dan Powell	Corrpro Canada Inc.	Calgary
38.	Reg Eadie	NRTC – University of Alberta	Edmonton
39.	John Skalski	Enbridge Pipelines Inc.	Edmonton
40.	Rick Doblanko	Enbridge Pipelines Inc.	Edmonton
41.	Jim Oswell	AMEC Earth & Environmental Ltd.	Calgary
42.	Ian Smith	Sun Canadian Pipeline	Waterdown, ON
43.	Brad Smith	Enbridge Pipelines Inc.	Edmonton
44.	Walter Kresic	Enbridge Pipelines Inc.	Edmonton
45.	Darron Mazurek	Tri Ocean Engineering Ltd.	Calgary
46.	Maury Dumba	Positive Projects International Ltd.	Calgary
47.	Jules Chorney	TransGas Ltd.	Saskatoon, SK
48.	Jill Hopkins	Conoco	Rock Spring, WY
49.	Catherine Pineau	TransCanada Pipelines Ltd.	Calgary
50.	Graeme King	Greenpipe Industries	Calgary
51.	Monica Santander	National Energy Board	Calgary

R-STRENG User Course

Pat Veith, CC Technologies

Pat Vieth, CC Technologies, described the historical development of the B31G and RSTRENG methods used to evaluate the pressure-carrying capability of corroded pipe and to ensure that an adequate safety margin is maintained. B31G was originally appendix G of the ANSI B31 code. RSTRENG stands for Remaining Strength. Both methods are referenced in the US Federal Regulations Part 192.485 as acceptable method to determine the remaining strength of corroded pipe, and the B31G method is embedded in CSA Z662. There are two versions of RSTRENG. The following table summarizes the key aspects of the methods.

Method	Flow Stress	Folias Factor	Area
B31G	1.1 SMYS	2 term for L^2/DT=<20	2/3 total length x depth
RSTRENG 85% Area	SMYS + 10,000 ksi SMYS + 68.9 Mpa	3 term, no length limit	0.85 x total length x depth
RSTRENG Effective Area	"	"	Iterative calculation to determine lowest failure pressure*

*The RSTRENG Effective Area method describes the profile of the metal loss area and uses an iterative calculation to determine the lowest failure pressure for all combinations of effective length and the associated metal loss area.

The RSTRENG methods were validated by comparing actual burst pressures from 90 experimental burst tests, hydrostatic test failures and service failures of corroded pipe and burst tests of machined slots.

The RSTRENG software was developed in 1991 and is recognized to have some limitations that make it "user hostile" and can make the output results confusing. It requires input data for the diameter, actual wall thickness, pipe grade and MOP, and the metal loss geometry. For the RSTRENG effective area method data is entered to describe the profile of the corroded area. For the 85% Area method, a profile must be entered that represents a maximum depth and total length.

When the calculated failure stress is greater than SMYS, no repair is required. If the failure stress is less than SMYS additional analysis is required to determine a safe operating pressure that will provide the intended safety factor.

The output identifies a safe maximum operating pressure that is based on a safety factor corresponding to the pressure at SMYS divided by the value entered for MOP/MAOP. The calculated factor of safety is the predicted burst pressure divided by the MOP.

Kiefner and Associates have an Excel spreadsheet called KAPA, (Kiefner & Associates Inc. Pipe Assessement) available at no charge from www.kiefner.com, that includes user instructions and performs essentially the same analysis as the RSTRENG software, as well as calculations for crack-like flaws whose failure depends on material toughness.

Attendees at R-Streng User Course Tutorial – April 9, 2001

1.	Bert Johnson	4J Ventures Ltd.	Calgary, AB
2.	Chris Horkoff	AEC Oil & Gas	Medicine Hat, AB
3.	Lorne Carlson	Alliance Pipeline Limited	Calgary, AB
4.	Artur Janz	ATCO Pipelines	Edmonton, AB
5.	Dave Hektner	BJ Pipeline Inspection Services	Calgary, AB
6.	Peter Chan	BJ Pipeline Inspection Services	Calgary, AB
7.	Mimoun Elboujdaini	CANMET Materials Technology Lab	Ottawa, ON
8.	David Jolivette	Canspec Group Inc.	Edmonton, AB
9.	Brian Paradis	Canspec Group Inc.	Edmonton, AB
10.	Stanley Wong	CC Technologies Canada Ltd.	Calgary, AB
11.	Don Wallace	Centra Gas BC Inc.	Nanaimo, BC
12.	Howard Wallace	Colt Engineering	Calgary, AB
13.	Bruce Moore	Conoco Canada Limited (PTC Pipeline)	Regina, SK
14.	Bob Coote	Coote Engineering	Calgary, AB
15.	Tanis Elm	Enbridge (U.S.) Inc.	Duluth, MN
16.	Scott Ironside	Enbridge Pipelines Inc.	Edmonton, AB
17.	Deb Billey	Enbridge Pipelines Inc. – contractor	Edmonton, AB
18.	Harvey Haines	Gas Technology Institute	Des Plaines, IL
19.	Chris Hartnell	Hunter McDonnell Pipeline Services	Billings, MT
20.	Shamus McDonnell	Hunter McDonnell Pipeline Services	Edmonton, AB
21.	Scott Arndt	Husky Oil	Lloydminster, SK
22.	Darryl Shyian	Imperial Oil Resources	Bonnyville, AB
23.	Delton Gray	Keyspan Energy Canada Inc.	Edmonton, AB
24.	Mark Johnson	Marr Associates	Calgary, AB
25.	Framci Jeglic	National Energy Board	Calgary, AB
26.	Doug Waslen	National Energy Board	Calgary, AB
27.	Minh Ho	National Energy Board	Calgary, AB
28.	Myles Artym	NeoCorr Engineering Ltd.	Calgary, AB
29.	Greg Van Boven	NOVA Research & Technology Corp.	Calgary, AB
30.	Neb Uzelac	PII (Canada) Ltd.	Concord, ON
31.	Christine Rubadeau	PII North America, Inc.	Houston, AB
32.	Bruce Hagerman	PII North America, Inc.	Houston, AB
33.	Gerry Wilkinson	Positive Projects International Ltd.	Calgary, AB
34.	Bryce Brown	Rosen Pipeline Inspection	Houston, AB
35.	Kyle Loewen	Trans Mountain Pipeline Company Ltd.	Sherwood Park, AB
36.	Mike Reed	Trans Mountain Pipeline Company Ltd.	Vancouver, BC
37.	Shawn McGregor	Trans Mountain Pipeline Company Ltd.	Kamloops, BC
38.	Mark Ottem	Trans Mountain Pipeline Company Ltd.	Burnaby, BC
39.	Blaine Ashworth	TransCanada Pipelines Ltd.	Calgary, AB
40.	Curtis Parker	TransGas	Regina, SK
41.	John Parsons	Tuboscope Pipeline Services	Houston, AB
42.	Theresa Bell	U.S. Minerals Management Service	Camarillo, CA
43.	Brian Ogden	Westcoast Energy Inc.	Hope, BC
44.	Errol Batchelor	Westcoast Energy Inc.	Prince George, BC
45.	Jennifer Wong	Westcoast Energy Inc.	Vancouver, BC

The Application of GIS Technologies to Integrity Management

Bruce Dupuis, Baseline Technologies Inc., Calgary

Food for Thought and Lessons Learned

GIS (Geographic Information System) should be thought of as functionality rather than necessarily an application. In essence GIS represents a map-based interface to a database. There are various levels of implementation of this functionality, these include:

- Image/document management
- Visualization tool to identify the spatial relationship of data and to locate data in space
- Spatial Analysis

What is particular to the application of GIS to pipelines is the consideration of chainage or the distance measure along the contour of the pipeline (how much pipe is in the ground from point A to point B). It is important to note that the GIS functionality is but one element of an effective data management solution for pipeline integrity. Unfortunately, a broad scope of other functionality has historically fallen under the umbrella of a GIS project. Aside from the general confusion this leads too, it also facilitates scope and cost creep as well as misplaced expectation. GIS functionality is not the silver bullet, but it is an effective and important piece of the puzzle.

One key functionality of a GIS is the capability to handle and derive GPS coordinates in an efficient and robust manner. However, this can lead to a misuse and over dependence of GPS data. Always be cognisant of the error band associated with GPS measurements and consider how it will impact any derived distance and positions.

The GIS functionality associated with an integrity data management solution can be implement a number of different means within a single organization depending on the use and deployment situations. The bulk of your integrity management needs may be fulfilled by a broader application of which GIS functionality is but one element, but this does not preclude the use of a separate GIS application to perform higher-level spatial analysis and modeling. In the same way you may utilize a separate risk management application. This "best of breed" approach assumes the underlying data structures are open and accessible.

Pipeline Database Models

Introduction of standard database models has only recently occurred within the pipeline industry. The Gas Research Institute developed the first pipeline model (ISAT - Integrated Spatial Analysis Techniques – circa 1994) for the purposes of introducing some commonality among transmission companies' Geographic Information Systems (GIS). The ISAT model has since been updated into PODS (Pipeline Open Data Standard – circa 1999) to better utilize a relational database structure.

Even though these database standards exist very few companies have been able to implement them in unadulterated manner because of their rigidity, non-conformance with existing in-house database structures, or for embedding spatial relationships in the database.

Benefits and detriments of existing pipeline database models will be addressed followed by a demonstration of a spatial implementation of the PODS database.

Overlay Errors in GIS

GIS is a powerful tool for analysis but most users are unaware of the errors that can easily propagate though various analyses. These errors occur, primarily, because GIS has made it too easy to combine data captured at varying scales and resolutions into one product. But is this the fault of the technology or an awareness issue with the user?

Presentation will cover a brief discussion on map scale, resolution, and data quality measures. Examples of map accounting for overlay errors will be shown along with a demonstration of how data quality can affect analysis output.

The Need for Metadata

Metadata is often defined as data about data. While this is a good high-level definition it glosses over some of the finer details and business reasons for its use. Metadata is better defined as the information or documentation that describes content, quality, condition, and other characteristics of data. With this definition in mind it, metadata is a tool that enables a company to better utilize data. Metadata enables companies to:

- Search and find data sources
- Document data for posterity
- Share data with other organizations.

Several standards exist for collecting Metadata but the one standard that has come to the forefront is the Federal Geographic Data Committee (FGDC). This is quickly becoming the North American metadata standard for government agencies and data clearinghouses.

Field Data Collection During Construction

Tracking of pipe materials during construction has become a best practice for many transmission companies. Recording and understanding metallurgy during construction can ease the task pipeline integrity during operations. There have been many efforts made to track pipe materials during construction all with varying levels of success and shortcomings.

Discussion will center on three common data collection methods used:

- Paper based,
- Barcodes and handheld computers,
- Barcodes, handheld computers, and GPS,

Issues and advantages of each method will be discussed and a demonstration of data use will be given.

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Managing Pipeline Integrity: Application of GIS Technologies to Integrity Management

April 9, 2001 1:30-4:30 p.m.

	Company	Name	Phone	E-mail	Signature
1	COLT ENGINEERING CORPORATION	DAVE WEBSTER	(403)258-8675	webster.david@colteng.com	
√ 2	KOCH PIPELINES CDN. L.P.	NEIL S. HAY	(403) 716-7670	HAYN@KOCHIND.COM	
√ 3	~~[illegible]~~ BJ Pipeline	Peter Chan	(403) 531-2520	pchen@bjservices.ca	
4	CORROSION & MULTIMEDIA	ANDREW WOZNIEWSKI	(403) 931-2974	woznie@attcanada.ca	
√ 5	PII NORTH AMERICA INC.	BRUCE HAGERMAN	(713) 849-6332	HAGERMANB@PII-USA.com	
√ 6	Trans Mountain	Mark Ottem.	(250) 371-4030	marko@tmpl.ca	
√ 7	TRANS MOUNTAIN	Greg Toth	(604) 739-5324	gregt@tmpl.ca	
√ 8	ENBRIDGE	BRAD SMITH	(780) 420.8607	brad.smith@cnpl.enbridge.com	
√ 9	Marr Associates	JOEL ASHWORTH	(403) ~~[illegible]~~ 258-2233	jashworth@marr-associates.com	
√ 10	Westcoast Energy	Jennifer Wong	(604) 691-5973	jjwong@wei.org	Jennifer Wong
√ 11	ATCO PIPELINES	Artur Janz	(780) 420-7536	art.janz@atcopipelines.com	
√ 12	NATIONAL ENERGY BOARD	Ken Yip	(403) 299-3195	kyip@neb.gc.ca	

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April 9, 2001 1:30-4:30 p.m.

13	CENTRA GAS BC INC	DON WALLACE	(250) 751-8319	DWallace@centrabc.wei.org	
14	WESTCOAST ENERGY	BRIAN OGDEN	(604) 869-5544	bogden@wei.org	
15	Nova Research & Technology	Katherine Ikeda-Cameron	(403) 250-4706	ikedack@novachem.com	
16	"	Greg Van Boven	403 250-0601	VANBOVEG@NOVAchem.com	
17	Hunter McDonnell Pipeline Services Corp	Chris Hartwell	406-698-3318	Chrish@hmpsi.com	
18	"	Shamus McDonnell	780-944-8884	shamus@hmpsi.com	
19	CORRIDOR PIPELINE	GREG HILL	(780) 416-2284	gregh@corridorpipeline.com	
20	[illegible]	[illegible]	[illegible]	[illegible]	
21	Greenpipe Industries Ltd.	Mark Webster	403-260-8776	markwebster@greenpipe.com	
22	Husky Oil	Scott Arndt	780-871-6553	Scott.Arndt@husky-oil.com	
23	SIMMONS GROUP INC	DON HERMAN	403 541 5308	simmons@cadvision.com	
24	CORRPRO CANADA INC.	Zane Reinhart	403 235-6400	Zane.Reinhart@corrpro.ca	

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Managing Pipeline Integrity: Application of GIS Technologies to Integrity Management

April 9, 2001 1:30-4:30 p.m.

25	Green Pipe Industries	SHARON HARDY	260-8787	sharon hardy@greenpipe.com	[illegible]
26	TUBOSCOPE	TODD PORTER	713 799-8160	tporter@tuboscope.com	TMP
27	TUBOSCOPE	JOHN PARSONS	713 799-5180	jparsons@tuboscope.com	JMP.
28	Tuboscope	Dave Boswell	780-955-8611		
29	Imperial Oil	Lorna Harron	780-955-6177	lorna.harron@esso.com	
30	Coote Engineering Ltd.	Bob Coote	403 247 1480	cooteb@home.com	B. Coote
31	National Energy Board	Franci Jeglic	403 299 2774	fjeglic@neb.gc.ca	[illegible]
32	COLT	DARIUS BOUCHER	259-1888	boucher.darius@coltEng.com	[illegible]
33					
34					
35					
36					

Pipeline Safety: Technology and Communication

Jim Dilay, Board Member

Alberta Energy and Utilities Board

Thank you for inviting me to the 2001 Banff Pipeline Workshop. CANMET and especially Winston should be congratulated on putting together what I believe will be another very successful workshop. This is the sixth workshop to be held since the first in 1993 and this venue has become known as an important and unique opportunity for pipeline issues to be discussed and resolved. This workshop is a clear example of the pipeline industry, pipeline engineering firms and pipeline regulators cooperatively working together to identify and resolve issues of the day.

To briefly acquaint those of you who may be attending from other countries, Canada's pipeline industry is regulated by a number of distinct agencies. Canada's National Energy Board is responsible for the regulation of interprovincial and international pipelines, and each province has its own regulatory body that is responsible for the regulation of intra-province pipelines. In Alberta, the Energy and Utilities Board (EUB) regulates the almost 300,000 km (186,000 mi) of pipelines wholly within Alberta. These pipelines include everything from the biggest natural gas transmission pipelines to the smallest production gathering pipelines, and everything in between. EUB-regulated pipelines transport a wide variety of products, not only natural gas and oil, but also ethane, propane, butane, pentanes plus, refined products, hydrogen, sulfur, produced water and ammonia - plus all the varieties of product mixtures that come out of the approximately 100,000 producing wells we have here in the province. Our pipelines are located everywhere: in the generally unpopulated areas of Northwest Alberta; the grass lands of Southern Alberta; agricultural heartland; forestry preserves; rural, suburban, and even urban areas. This variety and quantity of pipelines gives the EUB a unique perspective on the issues facing the pipeline industry. The issues themselves are not unique, they are similar to those in British Columbia, Saskatchewan, and other parts of Canada, but in Canada the density of pipeline development is currently the highest in Alberta. This is of course to be expected as Alberta currently produces the majority of Canada's oil and gas.

In a few moments, I will briefly discuss two key issues, and challenge you to consider them in your workshop sessions, to come up with new and creative ways to resolve those issues in ways that would not only ensure public safety, and environmental protection, but which will also be sound from economic and orderly development perspectives. By way of introduction though, let's first consider some good news and……some bad news.

The good news is that pipelines continue to be the safest way to transport the large volumes of product the long distances necessary to get them to market. Let's have a brief look at the importance and significance of pipelines in terms of products that are moved. In a year, more than 170 billion cubic metres (6 trillion cubic feet) of natural gas are produced from Canadian wells. This is enough gas to provide heating for over 30 million homes. Each year, more than 150 million cubic metres of hydrocarbon liquids (945 million barrels) are produced. Every day, Canadian pipelines deliver hydrocarbon liquids equal to more than 10,000 double tanker truckloads. Without pipelines, how would you effectively and safely deliver those products, and at what cost to the environment and the public?

In Alberta, it is a regulatory requirement that all pipeline failures, no matter how small, are reported to the EUB. Failure is defined as any release of product, whether from a pinhole leak or anything up to a total rupture, regardless of location, volume, or product type. The requirement to report every failure, along with the abundance of pipelines regulated by the EUB and the variety of products transported - many of which are highly corrosive - results in over 800 pipeline failures being reported to the EUB annually.

In general terms, we have found:

- Over 90% of failures are on small diameter, small volume gathering system pipelines, 168.3-mm (6-inch) diameter and smaller.
- About 87% of the failures are leaks, resulting in small losses of product.
- About 74% of the failures are due to internal and external corrosion.

In its fiscal year 1999/2000, the EUB conducted Operations Inspections of 69 companies and inspected 376 different pipeline systems to check their ongoing operations and maintenance programs. The EUB currently has more than 900 pipeline operators on record. Selection of inspection candidates is done taking into account the operator history, site sensitivity, and inherent risk of the operation. The EUB classifies unsatisfactory results into one of three categories:

- Minor, which are small deficiencies;
- Major, which are deficiencies that are having adverse impact or have potential to cause adverse impact;
- and Serious, which are incidents where total disregard for regulations and requirements has occurred and from which adverse impact is occurring or has the potential to occur.

None of the Operations Inspections resulted in a "serious unsatisfactory" rating. The overwhelming majority of recorded unsatisfactory items were minor in nature.

You will note that, despite the relatively high number of reported failures, we believe that the consequences of pipeline failures have been usually remediated quickly. The EUB is currently working with the Canadian Association of Petroleum Producers to develop a method to better record and assess the consequences of pipeline failures. From the failure and operations inspection information, there seems to be a positive record of performance. But could this record be interpreted differently? What about public response to pipeline development? This is what could be considered to be the Bad News - a perception by the public that pipelines are becoming unsafe - and this is one of the things that we are here to make improvements upon. So why is the public becoming more concerned about pipelines?

First, oil and gas development and related development of facilities is significantly increasing in Alberta and elsewhere. For example, in 1992, the EUB issued a little over 4300 drilling licenses. In 1997, it issued 13 000 drilling licenses and in the fiscal year just completed, we issued over 18 000 well licenses! The amount of pipeline activity resulting from increasing levels of drilling increases proportionally.

Second, with increased resource development in Alberta and in Canada, it is inevitable that more petroleum development is occurring near human habitation. At the same time, the human population of the province is growing. Census figures tell us that the population of Alberta has increased by one million people in the last 12 years. Pipelines are encroaching on an increasing number of people, and indeed people are encroaching on pipelines. This encroachment brings an increased real and perceived risk to people. As well, consider for a moment that about one third (46 billion cubic metres per year) of Alberta's gas production is from sour sources, meaning gas with a H_2S content of greater than 1%. This is likely to increase in the future.

Third, the public is demanding greater safety measures, less risk, and has become increasingly intolerant of environmental and safety incidents. The ability to quickly and easily access information from all over the world has enlightened people as to some of the more serious pipeline incidents such as those that occurred in Washington state and New Mexico, which included fatalities of members of the public. Some dramatic failures have also occurred in Alberta and elsewhere in Canada in recent times.

So, the net result is that the public is starting to feel uncomfortable about pipelines. They demand better pipeline performance; especially since oil and gas development is interfering with other uses of their land. Pipelines bring with them setback requirements and land development restrictions, both of which provide no compensation.
They look at the same statistics from the pipeline failures that we have previously discussed, but come to very different conclusions! Some are shocked that there are almost three pipeline failures per day in Alberta! Some suggest that as the pipelines are getting older, they must be also becoming unsafe!

As more people are living close to pipelines, some of them are choosing to participate actively in the consultation processes to ensure that their concerns are heard. Some feel they need to actively participate, as they don't trust the industry and regulators to resolve the issues. These concerns can result in a significant impact to the way that resource development is conducted in this province. Opposition, whether warranted or not, can result in significant and costly delays to development while these concerns are addressed. In some cases, where the impacts are judged to be unacceptable, denial of those applications may result.

So this leads us to the two key issues I mentioned a few moments ago, and that I hope can be discussed in later sessions to see what recommendations might be found. These are:

1. **How do we Ensure the Safety of Pipelines?**
2. **How do we Make Pipelines Acceptable to the Community?**

The sessions in the workshop intend to discuss both of these issues, not only from the technical aspects of design, operation and maintenance, but also the public perception aspect. Both are very important.

1. How do we ensure the safety of pipelines?

Ensuring pipeline safety involves many technical considerations. All of us here deal with these in some manner. The considerations necessary to get a pipeline approved, built and operating are commonly understood; issues like design, construction, operation and maintenance. For new pipelines this should be relatively straight forward, however, how extensively have you considered the long-term issues? Did you consider the corrosion mitigation and monitoring aspects during the design of the pipeline? What could you do differently during the design and construction stage to make the operation of the pipeline easier? How will you ensure that the proper techniques are used for pipeline construction? Do you have a documented operations and maintenance program BEFORE the start of operation to ensure that pipeline is operated safely and does not experience failures? Do you have a program in place to monitor pipeline integrity that will ensure that you know the condition of the pipeline and can deal with operational conditions BEFORE they could lead to a failure? Will you have proper documentation in place for materials, design, construction and operation of the pipeline? EUB Operations Inspections have shown that the majority of minor unsatisfactory items are related to record keeping.

With increasing drilling activity, consolidation of fields and the concern about well flaring, there is more demand to use existing pipelines. This may result in changes to the existing pipelines, such as using pipelines that have been discontinued from service or even abandoned, to re-certifying pipelines to higher operating pressures, or to carry different products. All of these modifications have unique safety considerations that must be thoroughly assessed before a decision is made to proceed. Would it be possible to develop specific standard requirements to ensure that the changes are done safely?

With oil and gas activity being closer to where people live, there is increased potential for third party damage to pipelines. What precautions or processes could be implemented to protect the pipelines from damage?

This is just a small sample of the questions that the public has about the safety of pipelines. The workshop sessions will hopefully touch on many of these technical questions and I challenge you to look for solutions that would increase your confidence, and public confidence, in the safety of the pipelines.

2. How do we Make Pipelines Acceptable to the Community?

This is a difficult challenge! It is not enough to do an excellent job in ensuring pipeline safety, the public must understand and believe that pipelines are safe. How do you determine if a pipeline is safe? What data do you use to determine the level of safety? If you use risk analysis, what is an acceptable level of safety? Why can it change from area to area? Why is it important that the public understand?

There are some obstacles that make clear communication of pipeline safety difficult. One is that there are many different data sources on pipeline safety, but each collects and presents the information in a different way. This makes comparison of the results difficult if not impossible and raises questions about the validity of the results.

Environmental and safety consequences of failures are not clearly documented. It is difficult to consistently assess the consequences in such a way that the public would accept the results.

Another problem is that any progress made in communicating about the safety of pipelines gets a major setback from each incident that is reported in the media and is perceived as having the potential to occur near people. How do you ensure that such incidents don't occur near people or environmentally sensitive areas and how do you share the knowledge with the public? How do you influence how incidents might be reported in the media?

These questions must be considered along with the questions about ensuring pipeline safety. The process will not be a complete success unless both aspects are addressed.

In conclusion ...

The EUB has a number of initiatives in place to address pipeline safety and provide information that can hopefully alter the perception the public has about pipeline safety:

- The EUB is developing a pipeline inspection manual and corrosion guide to ensure that inspections are conducted consistently, that compliance with requirements is correctly assessed, and that pipeline corrosion is managed.
- The EUB is expanding the field surveillance program to re-establish public confidence in the inspection program. The EUB hired new qualified inspection staff and has a program to increase inspection staff by 30 people over the next 4 years.
- The EUB has received valuable comments regarding the way it has collected and reported its annual pipeline statistics, and will endeavor in future to improve the ways it presents these statistics to achieve greater clarity.

- By April 2002, the EUB will review High Vapour Pressure pipeline safety and integrity requirements with external stakeholders, and identify and incorporate any necessary measures needed to assure public safety.
- The EUB is conducting Open Houses in communities around Alberta to directly interact with the public and to provide opportunity for sharing of information on issues specific to the area, including pipelines. If requested by the community, the EUB participates in public meetings to discuss and address issues about proposed and existing pipelines.
- Late last year, the EUB received the final report and recommendations of the Provincial Advisory Committee on Public Safety and Sour Gas. Some of the recommendations pertain to pipelines. A number of actions have already been taken by the EUB to address some of the recommendations. A documented plan identifying actions for each of the 87 recommendations will be made public this month.

The pipeline operators, designers and regulators must work toward a common understanding of the pipeline safety issues and then work together to resolve the issues and to make sure that the public has confidence in pipelines. Pipelines must be safe AND they must be understood by the public to be safe!

This cooperation between the pipeline operators, engineering staff, and regulators to come up with solutions to important issues is what makes this workshop unique. I challenge you to apply your creativity to devise new and productive ways to resolve the pipeline safety issues facing us today, and ensure a cooperative, productive working relationship between industry and the citizens of Alberta, as well as Canada, for future resource development.

Thank you very much for your attention and I wish you a very successful and productive workshop.

BANFF/2001
PIPELINE WORKSHOP

Pipeline Safety: Technology and Communication
Jim Dilay, Board Member
Alberta Energy and Utilities Board

EUB
Alberta Energy and Utilities Board

April 9-12, 2001 Banff 2001 Pipeline Workshop

Length of Pipelines in Alberta at end of 2000, km (miles)

- Total: 294,000 km (183,000 mi)
(all numbers arerounded)

•Crude Oil	17,000 (10,500)
•Nat ural Gas	173,000 (107,500)
•S our Gas	15,000 (9,300)
•Wat er	18,500 (11,500)
•Multipha se	46,000 (28,600)
•Othe rs	24,500 (15,200)

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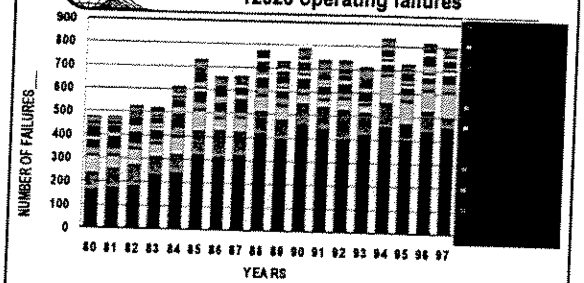
Pipeline Failures, by Cause 1980-1997 inclusive, 12328 operating failures



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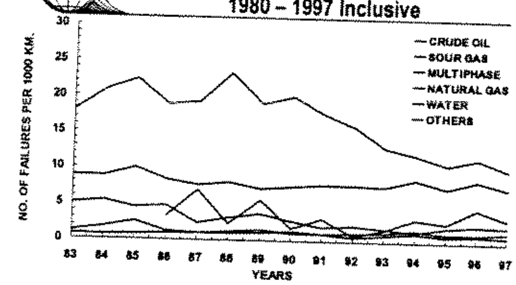
Frequency of Pipeline Failures Operating Failures – All Causes 1980 – 1997 Inclusive



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Alberta Pipeline Failures

- Over 90% of failures occur on 168.3 mm diameter and smaller pipelines
- About 87% of the failures are leaks
- About 74% of the annual failures are due to internal and external corrosion
- There are over 900 pipeline operators in Alberta

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Pipeline Operational Inspection

- Inspection selection is done by considering:
  - Operator History, Site Sensitivity, and Inherent Risk
- Unsatisfactory results rated into three types:
  - Minor: small deficiencies
  - Major: deficiencies having adverse impact or have the potential to cause adverse impact
  - Serious: deficiencies having total disregard for regulations and requirements and from which adverse impact is occurring or has potential to occur

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Increasing Resource Development

- In 1992, the EUB issued 4300+ drilling licenses
- In 1997, the EUB issued 13,000 drilling licenses
- In fiscal year 2000-2001, the EUB issued over 18,000 drilling licenses
- With more drilling, we will have more pipelines!

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Increasing Population

- In the last 12 years, the population of Alberta has increased by One Million people
- People are moving to rural residential areas
- Pipelines are encroaching on people
- People are encroaching on pipelines

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Why are People Concerned?

- Rapid access to information – better informed
- High profile catastrophic failures in other parts of North America
- Land Development Restrictions
- Setback Requirements
- No Ongoing Compensation
- Aging of the Infrastructure

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What are the Two Key Issues?

- How do we Ensure the Safety of Pipelines?
- How do we Make Pipelines Acceptable to the Community?

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How Do We Ensure the Safety of Pipelines?

- Proper design, with due consideration to long-term use
- Proper construction
- Proper operation, maintenance, and monitoring
- Proper evaluation of operational changes
- Control of Third-Party Damage

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How Do We Make Pipelines Acceptable To The Community?

- Must satisfy people that pipelines are safe
- Ensure statistical data collected is compatible
- Document environmental and safety consequences of failures
- Ensure that media reports in an objective manner

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EUB Initiatives to Address Pipeline Safety, and Public Understanding

- Pipeline Inspection Manual and Corrosion follow-up guide
- Expansion of the Field Surveillance Program
- Revision of the way statistics are collected and presented
- Review of HVP pipeline safety for 2002
- Open house meetings to address public concerns
- Adoption of recommendations of the Provincial Advisory Committee on Public Safety and Sour Gas

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The Key Message:

- Pipelines must be safe AND they must be understood to be safe!

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NEW TRENDS IN PIPELINE TECHNOLOGY

S. J. Wuori, *President, Enbridge Pipelines Inc.*
R. A. Hill, *President, Canadian Energy Pipeline Association*
M. A. Powell, *Chief Executive, PII Group Limited*
E. Glynn Jones, *Bechtel Pipeline*

Abstract. The technology applied to pipeline systems has evolved significantly over the past 30 years. During that time, societal attitudes and expectations toward energy development have also changed considerably.

Highly competitive market conditions and rising regulatory and public expectations, particularly in North America, have facilitated the rapid development of technological innovations for the pipeline industry. The resulting new technology is being applied to pipeline systems throughout the world, providing the answers to many complex issues associated with pipeline design, construction, operation and maintenance, and ultimately to public safety.

INTRODUCTION

The pipeline industry has experienced many changes over a short period of time, and change will be a constant well into the new millennium. One of the primary drivers of change is declining productivity in established sedimentary basins, such as the Western Canadian Sedimentary Basin. This has compelled the oil and gas industry to find innovative ways to reduce the incremental cost of production, and to look to frontier areas for new production. This in turn puts pressure on pipeline operators to lower transportation costs so shippers can remain competitive with other energy supply sources. At the same time, aging pipeline systems are incurring higher maintenance and operating costs to meet rigid safety and reliability standards. Compounding this trend, public expectations are rising to reduce the effects of pipeline construction and operation on the local community and environment.

While practices in pipeline design and operations continue to improve technologically, the public's expectation is often one of "zero tolerance" for errors that result in accidents or spills. Despite great improvements in environmental assessments, construction and restoration practices, and reductions of some 50 to 70% in pipeline spills over the last few decades,[1] an atmosphere of public opposition is increasingly apparent. This atmosphere of public resistance is becoming more common, manifested as opposition to new pipeline siting,[2] pipe rehabilitation[3] or expansion, route acquisition, and even opposition to the pipeline resuming operations after an accident.[4]

OPERATION and MAINTENANCE

1.1. Risk Management

Faced with rising expectations from the public and regulators combined with pressure to reduce costs from shippers, it's apparent that the international pipeline community must make safety performance a top priority while ensuring that spending on safety is directed to where it will have the greatest effect. Risk management programs are designed to fulfill this need.

Risk management, which includes risk analysis, helps decision-makers identify and prioritize effective risk reduction measures. It requires detailed reviews of operations and maintenance, and an estimation of the probability and consequences of various failures. Several new software tools are available that integrate data from many sources to provide the framework for a risk model. Furnished with adequate data and continually updated, the computer software can generate an analytical overview to help pinpoint sources of risk that may go unrecognized in management systems that are based only on regulatory compliance.

Pipeline operators in the United Kingdom and France have used risk analysis for several years to assess the need for pipeline diversions, proximity infringements and uprating. In the United Kingdom, the new Pipelines Safety Regulations support the development of risk analysis programs. In the USA, the Accountable Pipeline Safety and Partnership Act law provides a framework for the Office of Pipeline Safety to establish demonstration projects using risk management programs. Under these projects, companies are given some relief from government regulations if they can demonstrate that their risk management plans provide an equivalent level of safety. Australia, Western Europe and other countries are also moving in this direction.

Clearly, risk management may be the single best method for the pipeline industry to address public safety and environmental concerns while managing expectations of greater efficiencies and cost control.

1.2. SCADA Data Analysis

Most pipeline companies now use supervisory control and data acquisition (SCADA) systems to remotely operate and monitor their pipelines. A centralized SCADA system is an economical method to control not only the operation of a pipeline within a predetermined set of parameters, but also to capture data for further analysis.

Traditionally, SCADA data has been archived only to meet regulatory requirements for pipeline operational history in case of an incident. Increasingly, data from the SCADA system and other data from field locations constitute a wealth of information useful for analyzing all aspects of the pipeline operation.

By combining historical information with powerful data analysis software tools, engineers can scrutinize the operation of the pipeline in terms of power consumption, equipment performance, maintenance scheduling, pressure cycling and product quality. For example, data mining of archived SCADA data could be used to benchmark operator performance by how efficiently they operate a pipeline based on throughput versus energy. In doing so, patterns of "best" operation may be discerned that could be used to improve the performance of all operators or to find patterns that minimize energy use.

Electrical energy is typically the single largest cost of liquids pipeline operation. The combination of (a) the amount of electricity used, (b) the uncertainty of prices due to electrical deregulation and (c) the increasing pressure to reduce costs, presents a significant challenge to pipeline companies. The capability of a SCADA system to respond to the ever-increasing demands of energy management makes it one of the most powerful tools for managing energy costs.

Since data acquisition and analysis are key to managing power costs, an effective energy management strategy begins with accurate data collection. Comprehensive data analysis gives pipeline companies the confidence to evaluate all the potential rate structures, and to negotiate a customized power supply contract that better suits their operational and cost control needs. The result of proceeding without a complete understanding of the pipeline's power usage profile is to either incur a cost premium associated with a more conservative power contract, or to be exposed to an unreasonable amount of risk when a more aggressive contract is chosen.

Technical roadblocks to this type of operation no longer exist. Knowledge based expert systems and data mining software are now usable by a wider audience, rather than confined to highly trained application experts. Expert systems, or artificial intelligence, are developed by encoding expertise into "rules", which provide guidance or act as tools for the user. In the simplest applications, a user will query the expert system and be given procedures or suggestions as to how an expert might respond in the same circumstances. In more sophisticated applications, the expert system will examine the data, e.g., real-time SCADA data, and recommend a "best" course of action without a request from the user.

The operation of a pipeline is an ideal application for expert systems, and the SCADA data source is ideal for data mining. Today, pipeline companies are recognizing that there is value in looking at SCADA information using analytical techniques.

1.3. Leak Detection

Early recognition of a pipeline leak is critical to protect the public and the environment, and to preserve the company's credibility. Computational pipeline monitoring refers to methods used for detecting pipeline anomalies (which may be caused by a leak) through software algorithms that are fed SCADA data (flows, volumes, pressures, temperatures valve status). Because these systems depend on a large number of data points, and considering the complexity of pipeline hydraulics, it is often difficult for a pipeline controller to analyze the alarms and determine the cause with certainty. While simple rules or procedures can be imparted to the pipeline controller through training, the expertise of both the software developer and the pipeline controllers is sometimes necessary to determine the reason for an alarm. Recent advances allow an expert system to (a) look at the incoming data and the system outputs, (b) consider the encoded expertise of the application developer and the best pipeline controller, then (c) offer the controller immediate guidance.[5]

While the expert system could be programmed to act automatically, it will more likely remain a sophisticated tool to assist the pipeline controller. To improve the expert system, data mining and analysis of archived data should be ongoing, so that the system can become "smarter" over time. In this way, the thresholds of computational pipeline monitoring system alarms can be tightened, and the "advice" offered will become increasingly reliable.

1.4. Electronic Flow Measurement and Automated Operations

Not long ago, tank gauging or meters that recorded observed volume were used for custody transfer, and corrections for temperature/pressure were manually calculated. In the early 1980's, flow computers revolutionized this process. Flow computers use meter pulses and fluid property data (temperature, pressure and density) to calculate corrected volume, providing timely and accurate measurement while eliminating the possibility of human error within the correction calculations.

Since their introduction, flow computers have been linked to a number of systems that require custody transfer information. These include leak detection systems, inventory-tracking systems, batch tracking systems, and customers who require real-time information (accumulating volume, temperature, pressure, density, etc.).

In addition, flow computers now control peripheral equipment, including valves, samplers, etc., and receive non-measurement related signals such as gas detection alarms, man-on-site alarms, etc. These additions allow the flow computer to be used for all operational and SCADA requirements of a metering site.

The present trend within the pipeline industry is to maintain accurate flow measurement while streamlining the current processes for distributing this internally and externally. This is due to the ongoing goal of increasing operational efficiencies, and the customer's requirement for quicker/easier access to custody transfer information.

In the future, a common server will poll all flow computers along the pipeline. As injections and deliveries are terminated, batch information will be electronically transferred to the server and subsequently to a local database, which will store this custody transfer information. Various departments will be able to access the database, and ad-hoc reports will be available while eliminating the possibility of re-entry errors. Customers will have the option of viewing, approving and printing their tickets online. As well, they may print the custody transfer information to a file, then easily transfer it into their database/spreadsheet, thereby eliminating errors from manually re-entering the data.

PG&E Gas Transmission has recently made similar advancements to their electronic flow measurement system. Many of their flow computers are now polled to a central location, which allows measurement information to be more readily assessable, and shortens measurement cycles from a monthly to a daily (and soon perhaps hourly) cycle.[6]

Improved communication technology, such as wide area networks, will move the pipeline industry closer to a totally automated system. Custody transfer information will be transferred electronically, accounting and commodity tracking systems will become further automated and precise and, possibly, measurement audits will be completed "online".

1.5. Inline Inspection Tools

As the global pipeline infrastructure ages, there is increasing focus on technologies that allow pipelines to be operated safely and efficiently. These technologies, especially in the area of inline inspection (commonly known as "smart pigging") are now used by the vast majority of pipeline operators throughout the world to ensure security of supply for the world's hydrocarbons, and to extend the design life of over two million miles of high pressure pipeline—an expensive and vital asset.

When initially constructed, many pipelines had an economic design life of 20 to 40 years. In many instances, replacing these pipelines at the end of their design life is impossible. New techniques have been developed to keep pipelines in prime condition well beyond their originally planned life cycle. For example, years of research and development work have resulted in highly sophisticated inspection tools that have improved the ability to accurately determine the condition of pipelines.

Determining the condition of pipelines means not only identifying potential failure mechanisms, but also detecting such mechanisms long before they pose a threat to the integrity of the line. At the same time the tools must be accurate enough to allow pipeline engineers to discriminate among defects that may not be significant, thereby allowing optimization of maintenance and rehabilitation activity.

Inline geometry and metal loss tools have progressed significantly since the first prototypes were run well over 25 years ago. Since then, inline inspection has developed and matured into one of the most important technologies for preserving pipeline assets worldwide.[7] In the late 1990s, the pipeline industry witnessed and benefited from the addition of new inline inspection tools that can detect narrow axial external corrosion, cracks, stress corrosion cracking and other formerly indistinguishable pipeline defects.

With today's geometry inspection tools, the location and severity of pipeline dents, buckles, wrinkles and bending strain all can be measured to a very high degree of accuracy. In addition, the same tools now provide pipeline operators with three-dimensional geographic information via inertial navigation and sonar caliper measurements. Centerline axial data and internal cross-sectional details can be obtained in a single inspection run, allowing operators to determine the presence and dynamics of slope instability, subsidence, overburden, frost heave (common in the northern regions of Canada), free spanning, and changes in river crossings, over burden, temperature and pressure.

While magnetic flux leakage (MFL) is the oldest and most established technique for corrosion detection and measurement, in recent years ultrasonic technologies have emerged as a more accurate means of locating and quantifying defects. Commitment to R&D by the tool vendors has eliminated many of the earlier problems associated with ultrasonics, and the industry now has the benefit of inspection tools that provide extremely accurate direct measurement of not only defects, but also the thickness of the remaining wall. Ultrasound technology can also detect and differentiate among such other important features as laminations, inclusions, blisters, longitudinal channeling and narrow axial external corrosion.[8] With the ability to accurately classify defects, the operator can focus on the more severe defects and develop the most appropriate repair program.

Ultrasonic technique has been particularly effective in refined products pipelines, and the fundamental nature of this technology presently limits its application to lines carrying liquids. Several vendors are working on the challenges of deploying ultrasonics in a high-pressure gas medium. These projects require significant scientific research, in many cases in association with universities and technical research institutions worldwide.

Despite the success of MFL and other technology in qualitative and quantitative detection of corrosion and metal loss, the need to detect cracks at an early stage is still a serious challenge for pipeline operators. In response, inline inspection tools have been developed specifically to detect cracks. These tools, used successfully in several commercial inspection runs, allow a complete pipeline inspection with the entire circumference of the pipe scanned in a single run, with detection sensitivity for cracks and crack-like defects of 30 mm in length and of 1 mm in depth.[9] Due to industry collaboration and other developmental work, new tools are being developed and tested that could soon be used to inspect and detect varying crack-like defects. Included are the PII tool employing transverse field inspection (TFI) technology and the elastic wave (EW) inline crack detection vehicle.[10] As well, the French pipeline operating company, TRAPIL, has developed and tested a transverse MFL tool with the capability to detect stress corrosion cracks.

In combination with other existing and emerging technologies for inline inspection, and with ongoing improvement and further development, these tools will allow pipeline operators to address many integrity issues affecting their pipelines in the years to come. In the near future, demand from pipeline operators will likely lead to the development of multifunctional inspection tools that have the capability to detect corrosion, stress corrosion cracking (SCC), dents, cracks, etc. during a single run, which will further reduce operating costs. Another likely development will be to miniaturize today's inline tools to provide operators of small-diameter pipelines (168.3 mm, 323.9 mm, etc.) with the same capability, i.e., crack detection, that exists for larger lines.

1.6. GIS (Geographic Information Systems)

The development of increasingly sensitive and reliable inline inspection tools is, however, only one of the advances in pipeline integrity technology. Inspection vendors and pipeline companies have invested a great deal of effort into the analysis of increasingly large amounts of data. This data must be handled in a way that is cost and time effective, and must produce results that are "user friendly" if it is to be of maximum value to the pipeline operator. For example, to effectively use the information generated by inline inspection tools as a basis for a risk management system, appropriate software is needed that handles the full amount of data and integrates it with other relevant data gathered by the pipeline company. For many pipeline companies, a geographic information system (GIS) is the solution to this need.

GIS are specialty databases for storing, retrieving, manipulating, analyzing and displaying geographically referenced data, i.e., data identified according to their locations. The software combines common database operations such as query and statistical analysis with the unique visualization and geographic analysis benefits offered by maps. Mainline pipeline companies are joining distribution companies in turning to GIS to help map, monitor, and analyze data involving transmission facilities.[11] A GIS can contain all the information needed for right of way management and taxation, adjacent landowners information, survey data, emergency response plans, and situation reports for the pipe. The situation report can include centerline location and pipe condition, planning data for future inspections, e.g., inline inspection, cathodic protection, maintenance digs, and records of repairs and modifications. Records can include text, pictures, and any other digitized information. Data from inline inspections will automatically be read into the system, keeping it up-to-date. As well, alignment sheets can be generated quickly and accurately, reflecting current database information.

During the past decade, GIS technology has progressed from a system with potential to present day applications that provide a cost-effective operational and economic tool affecting virtually every aspect of the pipeline industry, from project planning through facility operations.[12] GIS technology is particularly advantageous for larger and more complicated pipelines systems that need to manage proportionate amounts of data.

In the future, GIS technology will provide improvements in efficiency, reliability, safety and risk management. By integrating GIS, Global Positioning Satellites (GPS), LEOs (low earth orbiting satellite), digital mapping software and portable computing power, along with new ways to communicate information visually, GIS will open up new opportunities for the pipeline industry to streamline and lower operating costs.

1.7. Satellite Technology used to Monitor Corrosion

Satellite communications provide a valuable service to the oil industry, particularly in remote regions. For the pipeline industry, the need for communication alternatives has always been an issue, since field facilities often lie outside the range of wireline communication, and pipeline corridors can extend thousands of kilometers.[13]

Recently, satellite technology has been extended to monitor internal corrosion of oil pipelines. For example, Enbridge Pipelines Inc. is now combining LEOs (low earth orbiting satellite) technology with the use of hydrogen flux foils (beta foils) to monitor internal corrosion activity in the more remote locations of its pipeline system. The company has used beta foil technology since 1995 for detecting and monitoring internal corrosion. This technology measures external hydrogen flux generated by internal corrosion activity, which generates atomic hydrogen atoms.[14] The hydrogen atoms in turn migrate through the pipe steel wall to the outside where they recombine to form molecular hydrogen gas (H_2). Depending on the level of internal corrosion, the hydrogen evolution detected by the hydrogen flux foil will indicate whether internal corrosion activity is high, low or nonexistent.

Field personnel routinely take readings in accessible areas, but some of the installation locations are in remote areas or not readily accessible. In such areas, beta foil readings are recorded by an above ground instrument, usually powered by solar panels. The data is transmitted to the LEO satellite and relayed back to global operation centers, where it is decoded, organized and transmitted back to the pipeline company, allowing personnel to monitor internal pipeline conditions regularly in remote areas without further expense.[15]

The pipeline industry will not have to look too far into the future before LEO and GIS technologies provide real time corrosion monitoring of pipelines and real time surveillance of existing pipelines corridors.

2. DESIGN and CONSTRUCTION

2.1. High Strength Steels

Technological advances in steel-making have resulted in the availability of new materials for pipeline construction. This began over 25 years ago with the development of thermo-mechanical rolling practices that brought high strength steel to the pipeline industry. In the early 1970's, Grade X-70 steel was used for the first time in a gas pipeline. As satisfactory experiences with X-70 led to its acceptance, during the 1990's Grade X-80 steel started to become widely used in large diameter, high pressure gas pipelines. In Canada for example, TransCanada PipeLines used X-80 pipe for over 300 km of large-diameter pipelines.[16]

More recently, X-100 grades have been achieved through further refinement of the manufacturing processes and are under assessment for future projects. Trial lengths of Grade X-l00 pipe have been produced and subjected to extensive testing by some major pipe producers and operators. Since 1995, Shell, British Petroleum and British Gas have been jointly researching the implications of using Grade X-100 grade material for design, construction and operation.[17] Further work is being done in the area of fracture propagation control, which is a concern of pipeline designers when high operating pressures are involved.

2.2. Automated Ultrasonic Testing

Weldability has historically been a concern when high strength steels are used in pipeline construction. Mechanized gas metal arc welding (GMAW) has become widely used in large diameter pipeline construction, usually in conjunction with automated ultrasonic testing (AUT) and an alternative defect assessment standard based on engineering critical acceptance. The recently constructed Alliance Pipeline saw the first use of these technologies in the USA on a major cross-country pipeline project.[18]

One of the past objections to mechanized welding has been that a defect found in welds made by the GMAW process—sidewall lack of fusion—is often hard to find and to quantify using conventional radiographic inspection. Extensive nondestructive testing with radiography and automated ultrasonics, coupled with the destructive analysis of an array of defects typically generated with mechanized welding processes, has resulted in absolute confidence that AUT can detect all relevant defects produced during mechanized welding.[19]

As well as a proven non-destructive examination (NDE) technology, AUT has made the transition to a viable process control method. Often welding defects do not occur randomly, but are a result of gradual malfunction or incorrect parameter settings of the welding system. With the resolving and accurate detection capabilities of AUT, many welding problems can be prevented before they cause weld repairs.

Increasing acceptance of automated welding technology may open the door to homopolar welding, a technology that allows a weld to be made in seconds, with the resultant joint as strong in tension and as tough as the parent metal. Industry participants in the Homopolar Pipeline Welding Research Program, managed by the University of Texas at Austin, have estimated that savings of 20–30% on total project cost may be possible, which could significantly change the economics of developing a particular field.[20]

2.3. Composite Reinforced Line Pipe

Several manufacturers are developing an interesting high strength material called composite reinforced line pipe (CRLP). This technology uses high strength fibre to reinforce a liner made of conventional steel pipe.

In manufacturing CRLP, high strength fibreglass is drawn through a proprietary resin, which ensures long term protection of the glass fibres, before it is wound in tension over the external surface of a conventional steel pipe liner. The two components work together to carry the applied load of a high pressure pipeline. This technology is an extension of the ClockSpring3composite repair sleeve technology.

This new technology also has some disadvantages. For example, longitudinal stresses must be carried solely by the steel liner, which has a reduced thickness compared to all-steel pipe.

2.4. Design Changes

Concurrent with the development of high strength steels, pipelines are being designed to operate at higher pressures using cost- and energy-efficient pump and compressor stations. A typical example of this trend is the Alliance Pipeline, a 2973 km $3 billion natural gas pipeline extending from northeastern British Columbia to Chicago, Illinois. This 914 mm and 1067 mm, Grade X-70 pipeline was designed to take advantage of high operating pressure (12 000 kpa) and a rich gas stream, which combine to allow a reduction in the power required to compress gas along the pipeline. In the United Kingdom, pipeline operators are using new risk-based analytical methods to support increased operating pressures for transmission pipelines. This new approach was made possible by changes made in 1996 to the Pipeline Safety Regulations, which now are based on a modern, goal-setting regime that requires operators to demonstrate that risks arising from the operation of a pipeline have been reduced to a level "as low as reasonably practical."

This new regulatory environment has allowed pipeline companies such as British Gas to explore higher operating pressure levels using a "limit states design" approach. By its simplest definition, limit states design is a risk-based method that incorporates the failure probability for segments of the pipeline system. In some cases, British Gas has been able to safely uprate segments of their transmission system from 7590 kpa to 8625 kpa with no increase in risk. In 1999, a group of world-leading pipeline engineering companies led by BG Technology launched a joint industry project to develop guidelines for applying the techniques now being used by BG. This will provide an accepted framework that will allow other pipeline operators to achieve benefits including capacity increases, maintenance reductions, life extension and reduced construction costs.

2.5. Slurry Pipelines

Slurry pipelines have provided safe commercial transport for many commodities since the mid-1900's. Commodities that have been successfully transported in slurry form include coal, iron sands and iron concentrate, copper concentrate, phosphate concentrate, limestone, zinc concentrate, and most recently, oil sand at the Syncrude mine in northern Alberta. Eric Newell, Syncrude CEO, says hydrotransport could be the key technology for expansion of oilsands mining.[21]

There are major deposits of shale oil and oil sands worldwide, and slurry pipeline technology can be applied to these materials as energy prices increase. As well, large coal deposits worldwide can be served by slurry pipeline technology for transport to market. The technology is current, with the 439 km Black Mesa coal slurry pipeline, which originates in Arizona, being in use since the early 1970's.[22]

High density polyethylene (HDPE) liners, which limit the potential for corrosion and wear in slurry pipelines, have recently been applied in the slurry pipeline industry. These liners are typically used in high-pressure slurry service, 24 150 kpa operating pressure being common.

Corrosion resistance requires a continuous HDPE lined system to be an effective barrier between the steel and the slurry. The liner is applied by pulling the HDPE liner through a diameter reduction unit into the line in continuous lengths up to one kilometer long. After insertion, the liner expands close to its original diameter, and "press fits" to the pipe wall.

Several other liner systems have been used worldwide including rubber lining for tailings applications, and polyurethane for highly abrasive slurries.

CONCLUSION

Change is inevitable, and nowhere is this phrase more true than in the pipeline industry. During the past several years, the industry has undergone substantial change resulting from highly competitive market conditions, technological developments, and rising regulatory and public expectations.

The pipeline industry must apply its expertise and technology to continue improving performance. Investment in internal inspection technology, maintenance, and inspection needs to focus on leak prevention and swift detection as well as efficient oil recovery, transportation and refining. In addition, information management capabilities must be tapped to allow each operator to analyze and control risks on a more comprehensive and cost-effective basis. Finally, constructive, proactive relationships with landowners, customers, communities and governments must be maintained to ensure the benefits of an efficient and safe pipeline infrastructure are fully realized.

All players in the industry must take responsibility for careful pipeline siting, environmental sensitivity, and performance improvements.

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2001 Banff Pipeline Workshop

"New Trends in Pipeline Technology"

Presented by Robert A. Hill, President
Canadian Energy Pipeline Association

New Trends in Pipeline Technology

- Presented at the World Petroleum Congress - June 2000, Calgary
- Co-Authors:

Stephen Wuon - Enbridge Inc.
Robert A. Hill - CEPA
E. Glyn Jones - Bechtel Pipeline, USA
M.A. Powell - Pii Group Ltd., UK

Rapid Technological Change

- Pressure on Costs
- Aging Pipeline Systems
- Public and Regulators have High Expectations by - 0 Spill Tolerance
- Landowner Pressures

Operation and Maintenance

- Risk Management
- SCADA Data Analysis
- Leak Detection
- Electronic Flow Measurement and Automated Operations
- Inline Inspection Tools
- GIS (Geographic Information Systems)
- Satellite Technology Used to Monitor Corrosion

Design and Construction

- High Strength Steels
- Automated Ultrasonic Testing
- Composite Reinforced Line Pipe
- Design Changes
- Slurry Pipelines

Conclusion

- Change is inevitable
- Technology key to improving performance

Working Group 1 - Issues for Managers in the Pipeline Industry

Tuesday, April 10, 2001, at 10:30 a.m.

Co-Chairs: Walter Kresic - Enbridge Pipelines Inc.
Dan King – TransCanada Pipelines Limited

Objective: To provide a forum for discussion and create an awareness of the various issues facing today's pipeline manager.

Overview: A presentation (attached) by the co-chairs provided the framework for discussion. A collection of viewpoints expressed by workshop participants is presented below. Key outcomes were summarized during the workshop and are presented at the end of these notes:

A "straw poll" conducted at the beginning of the session indicated that approximately half of the participants identified themselves as managers in the pipeline industry.

State of the Industry

Recent high profile pipeline incidents (Olympic Pipe Line, El Paso Natural Gas, etc.) and regulatory changes/initiatives were reviewed:

- Increasing public hostility towards pipelines appears to be aligned with increases in drilling activity and increased public opposition to new wells. Pipeline companies get lumped in with E&P companies and pipeline failures affect all of industry – "we are all painted with the same brush."
- Regulators are moving away from regulating the business aspects of the pipeline industry (tolls, tariffs, etc.) to more environmental and technical oversight.
- Considerable time is being spent in industry trying to understand business implications of new regulations. Regulations appear to be trending towards greater conservatism and the "regulatory pendulum" shows signs of swinging towards greater regulatory "intensity".
- Regulations in the USA are becoming more prescriptive in response to public outrage while Canadian regulations (OPR 99, etc.) are more "goal oriented" and less prescriptive. There is a general opinion that US-style pipeline regulations will eventually move north to Canada.

Pipelines and Perceptions

- Workshop participants were asked to consider if they would be willing to live next to a pipeline and what changes would have to be made in industry before they would do so.
- Negative perception stems from industry's inability to get a good message out. There was a general consensus that pipeline operators do a lot of good things, but only negative aspects are reported.
- Public perception that there is too much industry cost reduction and these cost reduction initiatives result in a reduced level of safety. There was an alternate view expressed that cost reducing initiatives do not necessarily affect safety performance. Amongst those opinions expressed, safety was help up as a core value.
- Does industry do enough to communicate "good news" i.e. volume safety moved, etc.?

CEPA indicated that it has spent considerable time and resources reviewing recent incidents and concurs with workshop comments regarding a greater need to communicate good things to the public. CEPA has established a committee and will be retaining additional support to better address public communications issues.

- In times of increased operating costs, tighter budgets, and human constraints, has risk modeling become a crutch to compensate? Industry must manage this perception.
- In order to reduce the negative industry perceptions, industry must foster a fundamental "grassroots" belief in pipeline safety within individual companies and amongst stakeholders.
- Are pipeline integrity management challenges perception problems or real safety issues?

Administrative Challenges

In addition to administrative challenges of increased demands on staff, external resources and budgets as identified by the workshop co-chair, additional immediate challenges identified by the group included:

- In spite of ongoing industry changes, there wasn't a strong reaction from the group regarding understaffing or budget constraints.
- Struggle to attract new people to the pipeline industry in general and specifically to pipeline integrity. Attributed to the relatively stoic image of the industry as compared to sexier "hi-tech" and to the historic volatility of the oil patch. (drives off lots of potential candidates seeking greater stability).
- Lack of balanced hiring practices and limited succession planning highlighted.
- Training; USA-style Operator Qualification requirements may come to Canada. Requirements to demonstrate proficiency (in an auditable manner) at the field level will be very expensive. (figures of several million dollars were quoted)
- The issue of specific technical expertise moving outside of companies and the general employment trend towards consulting and outsourcing was discussed. Pipelines and other industries (automobile etc.) previously embraced large staffs with various competencies. This has largely changed to outsourcing using specialization firms. Managers must adapt to a system where internal and external resources are employed efficiently

- The recent price of gas and corresponding desire to bring more gas on stream quickly has forced additional loading on older infrastructures as additional compression is added to old systems etc.
- Changing the mindset from "a small sweet gas release in the back forty" isn't that big a deal to "concern for all releases" is required to reduce overall leak statistics.
- General belief exists that additional funding could be obtained for key pipeline integrity issues if required.
- Lack of mentorship was identified as an industry issue. "Downsizing" of senior level staff (largely as a cost control measure) was suggested as a problem area affecting training of new employees. A suggestion was tabled that industry consider sponsoring a program at UofC or UofA to train people and increase industry profile.

Manager's Environment

Management Systems

- A common understanding regarding "what a management systems is and what it should it do" was not reached.
- Management Systems were generally defined as a "formalized decision making process" - used to demonstrate transparency. Strong regulatory (OPR99) endorsement of "systems approach"
- The general consensus within the workshop is that most participants have a series of programs to manage integrity, but it remains a challenge to assemble the "total package" and develop comprehensive documentation that brings together elements in an auditable fashion.
- Recommendations from those currently developing an Integrity Management System (IMS) are that systems should be developed as a iterative process with initial "rough cuts" being refined through time.
- Additional recommendations suggested that workshop participants not develop an IMS "in a vacuum" but rather leverage from other existing management systems such as Environmental Management System (EMS).
- Grouping together the integrity and EH&S audit components of management systems was cited as an example of a way to minimize impact to field operations.
- Any management system must start with a higher level strategy and become part of the corporate culture. The "buy in" for the underlying philosophy must exist from Senior Management through to line staff.
- Based on investigations of recent failures in the USA, a key post incident query involves review of the "system" in place at the time of the accident. As such, proponents must have (and be prepared to defend) a management system.
- ISO14000-type system may be too rigid or formalized to fit needs of all companies.
- Questions regarding overall value and appropriate degree of formality for a management system were largely unresolved.

Zero Failures

Are zero ruptures an attainable realistic goal?

- Opinions varied within the group as to whether this was an attainable target. Opinions were expressed that application of new technologies can make zero failures attainable while other suggested that the number of uncontrollable variables (third party strikes, etc.) make this target unreachable.
- If zero failures are unreachable, why is it being proposed as a goal.
- Although greater than 90% of leaks in AB occur on lines <6 inches in diameter operators of large diameter transmission lines are lumped in with small E&P operators as part of the broader leak statistics.
- As such, "the industry" is only as good as it's weakest link. What can industry do to move smaller companies away from "reactive" programs of leak repair towards prevention programs?
- Can a corporate culture be developed that embraces the ideal that integrity performance is an important aspect in the success of the company? Can tangible value be added through integrity programs?

SUMMARY & KEY MESSAGES

1. Public perception remains an industry problem. Only the "bad news" stories get heard in the public domain. Although it falls outside the traditional "core" pipeline manager role, managing public perception has become an important job aspect.

2. Prescriptive USA regulations and training requirements are expected to influence Canadian regulations and management programs.

3. No (admitted) concerns re: lack of staff or budget constraints; however, significant concerns regarding lack of mentorship, inability to attract talent to the field in light of competition from "sexier" hi-tech companies.

4. Varying views of management systems exist. There is little commonality regarding what a management system is or does. Some indications that individual parts (integrity programs) are enough, with a minority view that an overall management system is important. Most companies are at the stage of having several integrity management programs but not a "system". Significant challenges acknowledged regarding assembling program elements into an auditable package or system. Agreement that integrity management plans systems must have senior management support and become part of the corporate culture.

5. Diverse views regarding "zero failures". No resolution as to whether this is a viable goal.

BANFF/2001 PIPELINE WORKSHOP

Working Group #1
Issues for managers in the Pipeline Industry

April 9-12, 2001 — Banff 2001 Pipeline Workshop

Introductions

- Walter Kresic (Enbridge) - Co-Chair
- Dan King (TransCanada) - Co Chair
- Brad Smith (Enbridge) - Rapporteur
- Doug MacDonald (SNC Lavalin) - Facilitator

April 9-12, 2001 — Banff 2001 Pipeline Workshop — Slide 2

Issues For Managers in the Pipeline Industry

- First time this session has been held
- Our intent is to create awareness of issues among Pipeline Managers, create a common understanding and discuss possible approaches / solutions
- At the end of the session, we are required to summarize the key outcomes from our session

April 9-12, 2001 — Banff 2001 Pipeline Workshop — Slide 3

Recent High Profile Incidents

- **Olympic Pipe Line** *(Bellingham, Washington - June, 1999)*
  - Refined petroleum leak and fire causes three deaths
- **El Paso Natural Gas** *(Carlsbad, New Mexico - August, 2000)*
  - Natural gas explosion results in 12 deaths
- **Pembina Pipeline** *(Chetwynd, B.C. - August, 2000)*
  - One million litres of oil spilled into the Pine River contaminating drinking water.
- **Westcoast Energy** *(Coquihalla Highway - August, 2000)*
  - Natural gas pipeline rupture (no ignition) rained debris and blew windows out of nearby vehicles.
- **Exxon Mobil** *(Abilene, Texas - September, 2000)*
  - Bulldozer damages pipeline. One death and other injuries.

April 9-12, 2001 — Banff 2001 Pipeline Workshop — Slide 4

Regulatory Initiatives - United States

- United States Federal Legislation - Pipeline Safety Act
- OPS
  - Liquid Pipeline (>500 miles) HCA
  - Proposed - Liquid Pipelines (<500 miles) HCA
  - Proposed - Natural Gas Operater Integrity Management
  - National Pipeline Mapping System

April 9-12, 2001 — Banff 2001 Pipeline Workshop — Slide 5

Regulatory Initiatives - Canada

- NEB Publishes new OPR's in late 1999
  - audits underway
- AEUB report published in Spring 2000 indicates high failure rate and regulatory infractions on Alberta pipelines

April 9-12, 2001 — Banff 2001 Pipeline Workshop — Slide 6

State of Industry

- Are we evil?
- Are we Big Oil?
- Do you sleep well at night?

April 8-12, 2001 Banff 2001 Pipeline Workshop Slide 7

Administrative Challenges

- **The change in the industry / environment we work in is creating many administrative challenges.**
  - increased demands on staff
  - increased demands on external resources
  - increased demands on budgets
- **What other challenges do we have and do we have plans to address them?**

April 8-12, 2001 Banff 2001 Pipeline Workshop Slide 8

Manager's Environment

EVENTS → Business Drivers; Safety Issues

REPERCUSSIONS → Require New Skill Sets; Work Load

STRATEGIZE → Seek Innovation; Reprioritize; Manage Resources

IMPLEMENT → Management Systems

ACHIEVE GOALS? → Zero Ruptures / Failures

April 8-12, 2001 Banff 2001 Pipeline Workshop Slide 9

Management System

- **Formalization of decision-making approach**
  - Integrity Management Plan
  - NEB endorsed

1) What does this give us?
2) How formal should it be?

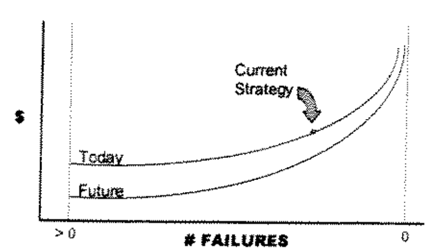
April 8-12, 2001 Banff 2001 Pipeline Workshop Slide 10

Operations Integrity Management

DRIVER	PROCEDURES, PRACTICES & SYSTEMS	ASSESSMENT	OBJECTIVE
• Management Leadership, Commitment & Accountability	• Risk Assessment & Management • Process and Facilities Information / Documentation • Personnel & Training • Operations & Maintenance • Management of Charges • Management of Third party Service • Incident Investigation & Analysis • Community Awareness & Emergency Preparedness	• Operations Integrity Assessment & Improvement	• Operations Integrity

April 8-12, 2001 Banff 2001 Pipeline Workshop Slide 11

Zero Ruptures / Failures



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Managing Pipeline Integrity: Issues for Managers in the Pipeline Industry
April 10, 2001 10:30 a.m.-12:00 p.m.

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80	TOM PESTA	EUB	403 297 8148	TOM.PESTA@GOV.AB.CA	
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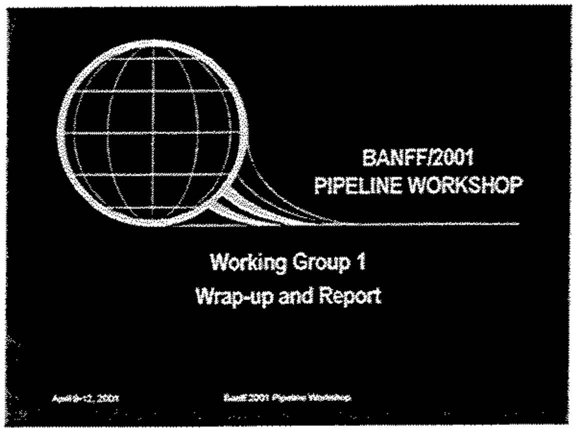
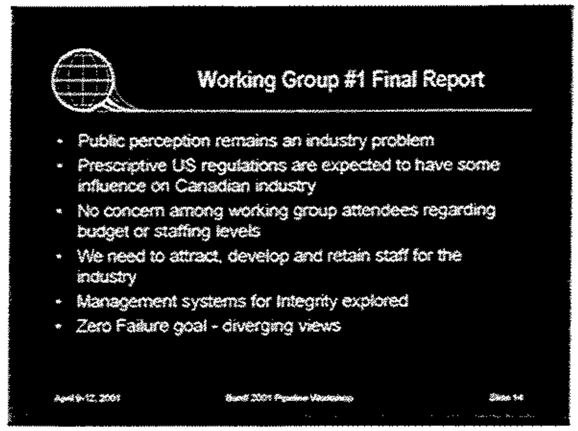

BANFF/2001
PIPELINE WORKSHOP
Working Group 1
Wrap-up and Report


Working Group #1 Final Report
Public perception remains an industry problem
Prescriptive US regulations are expected to have some influence on Canadian industry
No concern among working group attendees regarding budget or staffing levels
We need to attract, develop and retain staff for the industry
Management systems for Integrity explored
Zero Failure goal - diverging views

Working Group 2 - Regulatory Developments

Tuesday, April 10, 2001 at 1:30 p.m. – 5:00 p.m.

Co-chair: Tom Pesta Alberta Energy and Utilities Board
Co-chair: Ken Yip and Joe Paviglianiti, National Energy Board
Rapporteur: Lawrence Ator, National Energy Board

Objectives:

1. Is aging of pipelines a valid public concern?
2. The role of regulators in addressing public pipeline integrity concerns.

Presentation 1 - Aging Pipeline Systems
Mike Hallihan Skystone Engineering Inc.

Although there are failure mechanisms that are time dependent, statistics do not support the proposition that failures are more likely on older pipelines.
Statistics are not sufficiently clear to deal with the age issue and the statistics that are available might be leading the public to perceive that older pipelines are dangerous.

Presentation 2 - Aging Pipelines – A Landowner Viewpoint
Roy Baguley Metal Engineers International Inc

There have been a number of serious incidents involving pipelines. This justifies the concern that the public has regarding the safety of pipelines.
Pipeline companies will lie or mislead landowners with statistics.
The pipeline industry and pipeline regulators are seen in a negative light in public perception.

Discussion

There were four main issues that came up in the first session and were dealt with in the second session. These were: regulation, communication, financial concerns, and standards. The following is a list of the comments that were said about each on during the first session.

Regulation

The public perceives that regulators: do not operate independently, are in bed with industry, act more as mediators than regulators, and need to be hassled by the public to look at issues.

Regulators do not report incident information and statistics in a clear and consistent manner. Every regulatory body has a different definition for incident.

The consequences of incidents are not communicated by regulators.

When looking at statistics the public sees numbers of incidents but not the magnitude of each one.

There is a perception that the number of incidents is rising but fines and penalties associated with this are not.

Communication

Public perception is very real.

Age is a way for the media to focus issues when there is an incident. This might produce a public perception that age is a factor that produces dangerous pipelines.

The public relates corrosion to car rust, which is an age issue.

It is only human to assume that age will cause breakdowns.

Other industries have similar public perception problems. One industry that was compared with was the airline industry.
The airline industry has big media-covered disasters and yet are perceived favourably. Some of the reasons why this might be include the perception that airlines are high-tech, shiny machines while the oil industry is perceived as low-tech and dirty, airline crashes are seen as being out of the norm, and people volunteer to take the risks associated with air travel.

The incidents that get covered by the media are large scale disasters. The majority of incidents that occur are small.

Industry use the term 'age' as shorthand for a multitude of time related issues; this perpetuates the perception that age makes pipelines dangerous.

Financial Concerns

Facilities are used for longer than intended.

Old pipelines are not as easily inspected and newer pipelines.

The news reports pipeline sales.
The buyer of a pipeline is forced to rely on information about its condition from the seller.
There are increasing trends towards pre-sale inspection by the buyer.

If these inspections were made mandatory by regulators it would be easier for companies to justify the cost.

Is it acceptable for pipe that can't be inspected to have unlimited operational life?

Standards

Industry can develop good standards if they put the resources towards it. Regulators can comply them to do so.

External corrosion protection is required by standards. Why are there no requirements for internal corrosion protection?

What follows now is a list of the comments on each topic at the second session.

Regulation

There are two issues, public perception and pipeline performance.

There is concern that this discussion is calling for a less cooperative approach from regulators, contrary to the current trend of working together with industry.

There is a panel in Sundry that includes all stakeholders; it works well in a cooperative manner.

Regulators at the federal government level are perceived to be more independent. The example given is the TSB.

We should distinguish if a problem exists and if there is a bad public perception.
The NEB has perception as a goal.

Airline regulators are seen out there on the news after major accidents.

The NEB is out there with the TSB investigating major incidents. The NEB looks at every reported incident for causes.

There needs to be consistency with between regulatory bodies in the defining of incidents.

There is a danger that prescriptive regulation with force companies to spend their safety dollars inefficiently. We should establish performance measures and management systems to attain them.

There should be prequalification of companies who will operate pipelines.

Management system frameworks should be established by regulators.

Zero tolerance goal is too simplistic.

Application process should consider operating practices.

Maybe we don't need more regulation. As the public becomes more aware they prevent industry from pushing things through.

Offshore US companies are ranked. These rankings are public. This justifies more safety expenses to shareholders.

The cost of being responsible might take years to get paid back in the form of better performance, but it will get paid back.

Communication

Recall a W5 report where the reporter was able to use a rupture to make a mockery of an NEB official saying things were safe.

The best advocates of a good public perception are the people in this room.

The public perception in Saskatchewan is different while safety performance is largely the same. What the public sees in different places is largely what industry is reporting to them.

The media has to be better managed to form a good public perception.

Media operates by selling sensationalism.

The media affects the public at large, but landowners and those individually affected get there information in the form of packages from industry, followed by stonewalling.

Industry must impress upon the public how valuable industry is by using advertising to promote the industry.

Regulations should use a risk based approach to deal with both frequency and consequences.

It would be difficult to communicate a risk base approach to the public.

Communication to the public must be designed by people who have communication expertise.

Statistics won't convince people.

All stakeholders should be involved with communication strategy.

The public sees big money in industry and doesn't buy the financial limits arguments.

There should be pro active community awareness at the local level.

CAPP and CEPA could have working groups to develop a plan to communicate with the public. CEPA does have a communication initiative.

There are no CEOs here they are the ones who need to get the message.

The public perception impact by media coverage of big incidents is transitory. The landowner contact with industry is on-going and should be dealt with differently.

Associations can deal with general public concerns.

Individual companies can deal with site specific landowner concerns.

Financial Concerns

Industry functions by making money, and decisions are affected by this. There is a balancing act to try and satisfy all concerns.

The sale of the product is the only source of money in the industry. Regulation, production, transportation, refining, and landowners all get money from this 'pie'.

There is a strong correlation between the money spent on corrosion control and the number of incidents.

It is amazing how money becomes available when there is a catastrophe. Regulators and industry need to take the lead.

Industry should implement an integrity management program.

In the production industry the cost is not passed on to the consumer, it is market driven.

We could have CEO pay linked to safety performance.

We could link regulatory fees to safety performance like WCB does.

If standards are set up and required they become financial requirements.

Standards

We have been talking about risk of pipelines. Almost everyone has gas heating and that carries similar risks. We don't concern ourselves because we know there are standards. Standards create a feeling of comfort.

Are those standards not in place?

We should determine what is the base acceptable performance.

It is difficult to involve the public with standard development.

There is a lot mandated but it is not clear how it should all come together.

Common ground might be found with a ISO like quality standard. Auditable processes should reassure that problems won't be repeated.

Current standards are too broad they should separate different areas of industry.

The people who are not at the conference might be the problem.

We should enforce the current regulations, not make new ones.

There is too much interpretation involved with current standards. They need to be more specific to level the playing field.

There is an enforcement ladder that was put in place recently (AEUB). We should wait to see if it works.

Would like to see some kind of performance ranking for company. It gets attention with shareholders and makes it easier to justify safety expenses.

After the discussion the two presenters made closing comments.

Roy Baguley's Closing Comments (paraphrased)

What it would take is meaningful regulations enforced meaningfully. Public had to make effort to enlighten regulators this is not right. Level the playing field.

Mike Hallihan's Closing Comments (paraphrased)

Take the time to talk to people who you affect who don't work in oil industry. It is a bad idea to have engineers tell landowners 'what is what' in their lives. We need to have better statistics and information. It's about trust.

BANFF/2001 PIPELINE WORKSHOP

Working Group 2 - Regulatory Developments A Summary of the Discussions

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Why is Pipeline Aging a Concern?

- Is the issue of aging just a convenient target?
- Despite industry efforts, public perception will remain for extended time
- What are other industries doing? Industries like air transport and rail transport also have safety issues, but do not seem to have the same problems with public perception. Why?
  - They are highly regulated
  - Personnel are highly trained, credentials are documented
  - we accept the risk of air travel willingly, it is not forced upon us

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Why is Pipeline Aging a Concern? Continued

  - Aircraft may be more easily inspected
  - pipelines are not as high-tech as aircraft
- Corrosion is not fully understood by the general public
- Is there an automatic assumption that everything has a finite life-span?
- Should we automatically assume that all pipeline leaks are bad?

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How Have the Regulators Affected Public Perception?

- There is a perception the regulators may not be working fully in the public interest
- Is it reasonable to allow an unlimited life for a pipeline?
- Regulators are lax in inspection during construction
- Regulators could specify more integrity management
- Failure statistics should be fully available and presented without any spin
- The regulators should set performance standards, measure against them, and report on performance
- Regulator should impose more fines and prosecution

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Technical issues that may be contributing to the problem

- Old designs may make today's maintenance difficult
- Major differences between upstream and downstream
- Age is irrelevant! The issue is lack of inspection and maintenance
- Production declines in aging systems will create cost pressures for maintenance of marginal systems
- Technical records are sketchy for old facilities
- Are companies properly conducting due diligence?
- Construction done as cheaply as possible in cases
- Industry must perform a balancing act between funds available and technical needs

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Communication Problems

- Catastrophic transmission line failures cause a false perception of the consequence of a pipeline failure
- Frequent failures on upstream lines cause a false perception of the frequency of failures on all pipelines
- Even technical publications may be reinforcing the "aging" concept
- Risk is driven by the numbers of failures occurring
- Terminology - use the term "maturing" pipelines instead
- The media does not report objectively on pipeline incidents
- Statistics are easily manipulated or easily misunderstood

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Standards

- Industry could come up with better standards and the regulators could adopt them. Industry would buy in to their own standards more readily
- Modern standards are usually the result of public pressure on regulatory authorities
- Existing Standards not clear on the expectations for pipeline integrity management

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A Summary of the Key Issues Developed During Session 1

- Regulatory issues
  - require independence and transparency
  - Must ensure compliance through enforcement
- Financial constraints
  - on industry, on regulators, on public
- Communication problems
  - performance statistics, regulator communication, industry communication
- Standards
  - development, requirements, involvement

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Regulatory Issues, Possible Solutions

- panels of stakeholders working together (SPOG)
- regulator should be an independent body
- need strong presence, with immediate action & investigation
- Each regulator has a purpose which may influence the way they report their information
- Industry and regulators set a benchmark as to acceptable level of performance
- include commitments for operation and maintenance

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Financial Constraints, Possible Solutions

- Evaluate how the wealth is distributed
- Regulators help finance technology development that might assist industry performance
- Examine or audit financial expenditures towards integrity and ensure it reflects volume of actual production
- Mandating integrity management programs might eliminate the issue of financial constraints
- Find way to pass increased costs on in a commodity market

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Financial Constraints, Possible Solutions Continued

- Prioritize according to consequence - use risk based approach
- Tie corporate bonuses to pipeline performance
- Reduce risk to a level at which increased financial expenditure would not result in further reduced risk
- Consider WCB model - more leaks equates to more costs (higher levy or fines)

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Communication Problems, Possible Solutions

- Pre-qualification (have regulator evaluate and verify quality of operator)
- Zero-tolerance comments are a distraction to real issues
- Must define the problem, and then design a solution
- Technical people may not be the best to talk to the public
- Public sees high corporate profits
- Risk based approaches require careful communication
- Include requirements for maintenance in regulations
- Use proactive regional communication programs (SPOG)

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Communication Problems, Possible Solutions Continued

- Have CAPP and CEPA develop public communication
- Get the small producers on board
- Get support at the CEO and Director level
- Communication needs to be different for different levels of involvement, i.e. directly affected public vs. indirectly
- Associations are most appropriate to communicate generally on global issues
- Companies should do the communication on local issues
- More careful reporting of failure statistics
- Make failure statistics fully available

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Standards / Regulations Possible Solutions

- Standards make it easier to mandate work
- industry and regulators should establish key performance indicators to verify that Standards are working
- implement a quality standard e.g. ISO9000
- Standards are very broad (minimums), leave too much room for interpretation. Make more specific to the application
- Don't need more Standards, need more enforcement
- Prescriptive Standards not suitable for variable situations

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BANFF/2001 PIPELINE WORKSHOP

Aging Pipelines - A Landowner Viewpoint

Roy Baguley, P. Eng.
Metal Engineers International Inc.

April 9-12, 2001 — Banff 2001 Pipeline Workshop

What have you left in my backyard, and how are you taking care of it?

- Presentation Objectives:
  - To present a landowner view of pipeline safety and integrity.
  - To promote a discussion of these views aimed at finding answers to landowner concerns.

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Why are Landowners Concerned About Pipeline Integrity?

- Increased public awareness of the hazards & consequences of failure.
- August 21, 2000, Carlsbad, NM, 30" natural gas pipeline explosion kills 11 people camping about 600 feet away.
- With headlines like this, it is understandable that landowners and the general public are increasingly concerned about the integrity and safety of our pipelines.

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It Couldn't Happen in Canada, Could It? It's Just an American Problem, Isn't It?

- Just because much of the media attention has focused on recent American pipeline failures and regulatory issues doesn't mean Canadians don't have similar concerns.
- How many people remember the 1979 Millwoods pipeline failure and evacuation, that is a source of concern for residents living in the area?
- How many of you have been exposed to the increased local area resident resistance to sour gas development? What are the reasons behind this resistance?

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Three Landowner Questions About Pipeline Safety

- Are pipeline incidents/failures on the increase?
- Are older pipelines at higher risk of failure?
- What are pipeline companies and regulators doing to maintain or enhance pipeline safety?

- When answering these questions, please consider that there are three kinds of lies:
  - lies;
  - damned lies; and
  - statistics. (Benjamin Disraeli, Prime Minister of England, 1868)
- Landowners are regularly subjected to all of these.

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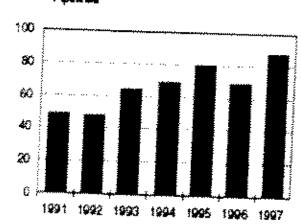
Are incidents on NEB regulated pipelines on the increase?

Figure 4: Total Reported Incidents on Federally Regulated Pipelines



- Looks like a simple test. What do you think?

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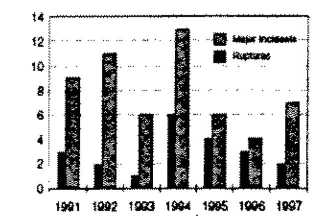
Are major incidents and ruptures on NEB regulated pipelines increasing?

Figure 6: Major Incidents and Ruptures on Federally Regulated Pipelines



- What do <u>you</u> think - decreasing, increasing, or cyclic?

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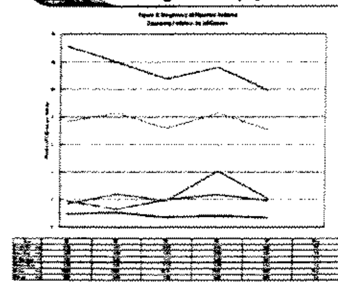
Is the frequency of failure for EUB regulated pipelines on the increase?



- It depends on the product.
  - Water (blue) appears to be declining.
  - Sour gas (red) appears to be increasing, or is it?
  - Natural gas (yellow) appears to be flat.

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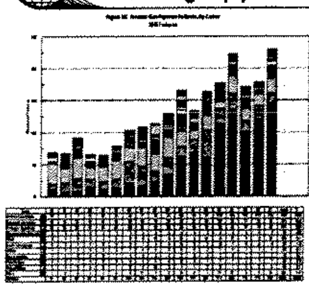
Are the number of EUB regulated natural gas pipeline failures increasing?



- The answer looks obvious, doesn't it.
- But, in view of the previous slide, is industry now going to tell me as a landowner that the frequency of failure isn't really going up, it's just the number of failures that's increasing?

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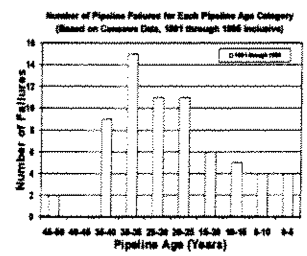
Are the number of pipeline failures related to the age of pipelines?



- European data indicates there are more failures in older pipelines than newer pipelines.

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The Job of the Regulator

- By way of example the NEB says that it is responsible <u>**for ensuring the safe operations of pipelines**</u>, and it has published the following corporate goals:
  - Ensure that NEB regulated facilities are <u>**safe and perceived to be safe**</u>.
  - Ensure that NEB regulated facilities are built and operated in a manner that <u>**protects the environment and respects individual's rights**</u>.
- I would propose that other regulators have similar goals and objectives, although they may be stated differently.

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Landowner Perceptions

- Pipelines are dangerous.
- Old pipelines are more dangerous than new pipelines.
- Regulators are not doing their jobs (or can not).
- Regulators behave more like mediators than regulators.
- When incidents occur, industry just gets a slap on the wrist.
- Industry is doing little to maintain pipeline safety & integrity.
- Industry <u>**thinks**</u> they have a good safety record.
- Profits come before people...

<u>**"If new technology costs $10 more than old technology, you can be damned sure the operator on my place won't be using it."**</u>

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Primary Result of Landowner Perceptions: A Call for More Regulation

- Need for clear and effective regulations that will force companies to pay attention to pipeline integrity and safety.
- Enforcement of such regulations by impartial autonomous regulatory agencies.
- Severe and meaningful penalties and compensation orders for companies that do not adhere to regulations.
- Revocation of licenses for operators with serious or chronic non-conformances.

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Secondary Results of Landowner Perceptions

- Simple mechanisms for public input to decision-making processes, and compensation for those directly affected.
- Consideration of risk, exposure, and loss of enjoyment in the assessment of land values.
- Disclosure of all facts with applications to construct, and throughout the approval process.
- Impartial audits of Regulator performance respecting the administration & enforcement of Acts & Regulations.
- A system that requires pipeline companies to be pre-qualified by the Regulator before being given permission to build and operate pipelines with hazardous products.

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Secondary Results of Landowner Perceptions (Continued)

- Periodic publication of the results of Regulator activities including facility names, operator names, and locations.
- Improved data collection by regulators & communication of results without spin & other "fun with numbers".
- Industry funded research into pipeline safety, integrity, and risk, that is administered by Regulators and carried out in an environment independent of industry influence.

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PIPELINE WORKSHOP

Aging Pipeline Systems

Michael Hallihan P. Eng
Skystone Engineering Inc.

April 9-12, 2001 — Banff 2001 Pipeline Workshop

Aging Pipeline Systems

Old Age Does Not Cause Failures!

All failure causes are time dependent!

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Aging Pipeline Systems

The 5 Prime Pipeline Failure Causes

- Corrosion – progressive
- Environmental Cracking – instantaneous
- Overpressure – progressive
- Overload – instantaneous
- Material Defect – instantaneous

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Aging Pipeline Systems

Progressive failure causes are;
- predictable (mode, rate & location), and
- controlled with preventative maintenance

Instantaneous failure causes are;
- unpredictable (mode, rate or location) and
- controlled with repair, replacement or redesign

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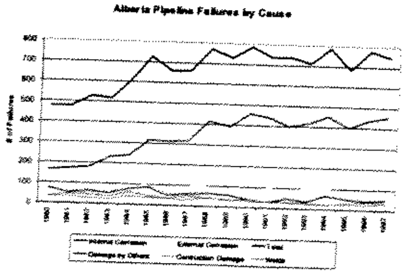
Aging Pipeline Systems

Alberta Pipeline Failures by Cause



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Aging Pipeline Systems

The 5 stages of pipeline life
- Design
- Construction
- Operations
- Maintenance
- Abandonment

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Aging Pipeline Systems

Design Activity Errors
- Pressure design
- ROW stability design
- Materials selection/quality
- Thermal design

Construction Activity Errors
- Joining (welding, MIF, Fusion, etc.)
- Construction Impacts

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Aging Pipeline Systems

Operations Activity Errors
- Overpressure

Maintenance Activity Errors
- Internal Corrosion
- External Corrosion
- Third Party Damage
- Earth Movement
-

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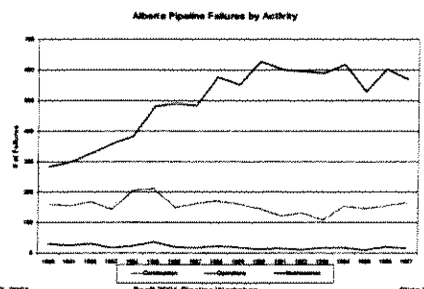
Aging Pipeline Systems



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Aging Pipeline Systems

Of 853 Pipeline Incidents in 2000
- 42% occurred on lines less than 10 years old
- 30% occurred on lines 10-20 years of age
- 20% occurred on lines 20- 30 years of age
- 7% occurred on lines 30-40 years of age
- 1% occurred on lines older than 40

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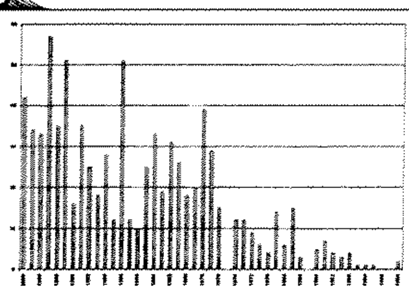
2000 Incidents by Year of Construction



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Aging Pipeline Systems

Age Does Not Cause Failure
- All failure causes are controllable irrespective of pipeline age.
- Each foreseeable failure mode, rate and location must be identified to be controlled.
- Most failures are due to inadequate maintenance.
- Maintenance must be designed to control every failure cause.

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Aging Pipeline Systems

Improvements

- Continue to reduce failures due to design, materials, and operations thru improved standards and compliance.
- Reduce failures due to inadequate maintenance by establishing clear standards and competency for planning maintenance.

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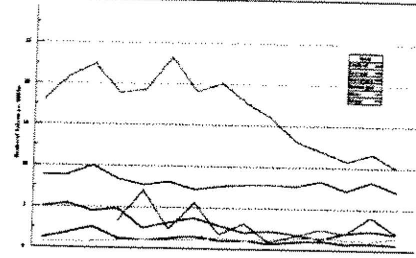
Aging Pipeline Systems



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Managing Pipeline Integrity: Regulatory Developments
April 10, 2001 1:30 p.m. - 5:00 p.m.

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Managing Pipeline Integrity: Regulatory Developments
April 10, 2001 1:30 p.m. - 5:00 p.m.

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BANFF/2001 PIPELINE WORKSHOP

Working Group 2 - Regulatory Developments Outcome and Conclusions

April 9-12, 2001 Banff 2001 Pipeline Workshop

Company Logo Goes Here

Working Group 2 - Regulatory Developments

- Theme: Aging Pipelines are Unsafe
- Two Presentations:
  - Roy Baguley - Aging Pipelines - A Landowner Viewpoint
  - Mike Hallihan - Aging Pipeline Systems
- Viewpoints:
  - Pipeline Reliability Declines with Age
  - Pipelines Are Safe Indefinitely if Maintained Properly

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Sample of Comments Received During the Session

- Regulators do not operate independently, are too friendly to industry, act more as mediators than regulators, and don't act on issues until pressured by the public
- There was much discussion on how the pipeline industry is perceived against other transportation, such as airline or rail travel, where regulation is perceived to be very strict
- Media has strongly influenced the public perception
- A variety of financial concerns have influence
- Standards are perceived as being inadequate or inadequately enforced
- Regulators should establish performance measures and hold the companies accountable through penalties

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A Summary of the Key Issues Developed During Session 1

- Regulatory issues
  - require independence and transparency
  - Must ensure compliance through enforcement
- Financial constraints
  - on industry, on regulators, on public
- Communication problems
  - performance statistics, regulator communication, industry communication
- Standards
  - development, requirements, involvement

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Possible Solutions

- Regulatory Solutions:
  - need strong independent presence, with immediate action & investigation of major incidents
  - Industry and regulators set benchmarks for acceptable level of performance and develop a ranking system
- Financial Solutions:
  - Consider WCB model - more leaks equates to more costs (higher levy or fines)
  - Reduce risk to a level at which increased maintenance expenditure would not result in further reduced risk

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Possible Solutions

- Communication Solutions:
  - Have CAPP and CEPA promote the industry
  - More careful reporting of failure statistics
  - Use Risk assessment to evaluate, not to communicate
  - Proactive regional communication programs (SPOG)
- Standards / Regulations Solutions:
  - Improve inspection and enforcement rather than build more regulation (meaningful regulations, meaningfully enforced)
  - CSA develop appropriate standards, regulators enforce them, industry must develop appropriate practices

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Working Group 3: Upstream Pipelines Inspection, Corrosion and Integrity Management

Wednesday, April 11, 2001, at 8:30 a.m.

Chairmen:
- Reg MacDonald
- Dave Kwas
- Alan Miller

Rapporteur's Report

Reg MacDonald welcomed the attendees and presented the highlights from previous Pipeline workshops.

The key outcomes from previous workshops are summarized as follows:

- Banff 99: Advance techniques for corrosion monitoring
- Banff 97: An industry consortium to predict internal pitting corrosion of multi phase pipeline (due to finish in 6-8 months time)
- Banff 95: Risk assessment (More companies are performing it now)
- Banff 93: Laboratory methodologies for corrosion inhibitor evaluation (The outcome of a joint industry consortium formed that the basis of an ASTM Standard, that is expected soon)

- The industry is changing as a result of the Banff Pipeline Workshop.

Reg also noted that in the Banff '99 workshop, upstream pipeline had one session, but in Banff 2001, we have one full day to discuss the upstream pipeline issues.

He concluded that the success is due to the fact that the people attending the workshop will be able to take home some values that will help to perform the work better.

<u>Bernie Frost presented the Regulator's perspective – "An Action Plan for 2000 – 2004"</u>
To a question as to how many companies do not have corrosion mitigation program, Bernie answered that about 50-60% have mitigation program, but not necessarily monitoring.

He noted that in the past there were no penalties for non-compliance, but penalties may come in the future.

Bernie further informed that the EUB direction on consequence is expected in fall, 2000. He categorized three levels and presented the details on actions items and consequence in each category:

- Minor Levels (1, 2, 3, and 4)
- Major Levels (1, 2, 3, and 4)
- Serious Level
- The category will be "minor" if mitigation is in place, but not properly operated.

- The EUB is producing a "Frontline Stakeholder Awareness Corrosion Guide" and enforcement action.

The issue of training the inspectors was discussed at length. The Department of Transport, U.S.A., is taking training seriously.

In Canada, the personnel dealing with sour gas are trained, but not necessarily those involved in crude or water lines.

Keith Cartmell presented data on the pipeline failures in Alberta.
He advised that the majority of the 852 failures are on natural gas (30%), oil emulsion (22%) and salt water (9%).

- The major cause is INTERNAL CORROSION.

One graph describing the total number of failures over the years showed an increasing trend, while another graph showed that the number of failures remained flat. **It was observed that a detailed analysis should be performed on the data before any meaningful conclusions can be drawn.**

- The majority of the failures are occurring on 6" pipelines.

The EUB regularly produces a report on pipeline failures. The most recent report was released in December 1998. Detailed data on the pipeline failures in Alberta are available in the EUB Report 98-G, December 1998.

Ian Scott presented "Upstream Pipelines: Inspection, Corrosion and Integrity Management" (Consequences of Pipeline Failures)
He advised that a CAPP Task Group is working on this issue. He advised that this effort is coordinated with CEPA, EUB, NEB and non-government organizations).

The consequence of pipeline failures can be classified into low, medium high.

There is a memorandum of understanding between CAPP and Alberta Environment. CAPP is also soliciting comments from the APESC Committee. The plan is to have a "1-Year Pilot Project"

To a question, Ian advised that, based on the previous year's data, most of the consequences are classified between low to medium. Very few consequences are high.

The Public does not care about the volume of spills but rather they are concerned about the number of spills.

The issue of training of operators was discussed.

With Regard to the Need For An Internal Corrosion Management Program
- There should be a good Internal Corrosion Management Program in place.
- The Producers should meet to set practices and/or guidelines for field operators.
- Industry should move to a pro-active state from the reactive state.
- In many cases the program is in place, but not applied properly.
- The industry should obtain self-auditing status.
- The issue of larger vs. smaller companies was discussed.
- There should be a minimum set practice.
- There is a CAPP Pipeline Technical Committee for CAPP members.
- There should be a sponsoring organization, e.g., CAPP to develop and maintain the document on corrosion management.
- Such a document can be first developed by CAPP, and could be moved to CSA.
- Relatively few upstream personnel are on CSA committees.
- The CSA Production Subcommittee is searching for members. Without improved interest, the Subcommittee may be disbanded.
- Similar documents from others (e.g., DAOAC) can be used as a guide.
- At present producers are in charge and they develop corrosion control practices. The EUB may review them.
- The issue of accepting a standard was discussed. It is observed that the standard should be considered as minimum guideline.
- To a question on the current level of inspection of failures - the EUB advised that the about 90% have been inspected. The reports of these inspections are being prepared. The intention is to complete the inspection and report in all cases.

James Ferguson presented "A Framework for Integrity Management for Internal Pipeline Corrosion"
How many companies are going beyond the EUB requirements on integrity management? A show of hands indicated that about 10 companies that were represented at the session go beyond the EUB requirements.

The guidelines do not go far enough; therefore it is necessary to go further on integrity management.

What are the different standards available on integrity management?

U.S. regulatory requirements (API) are being produced.

CSA Z662.99 has a non-mandatory clause on risk assessment.

Can regulatory standards be used for integrity management?

Risk control is presently out of the scope of the CSA Z 662.99 appendix on risk assessment.

Industry, the regulator, and the public have different perspectives on risk.

Can predictive models play a role in integrity management? Models are a less concrete rule, but can be used as a factor that contribute to corrosion mitigation and to rank the system appropriately.

The issue of Risk Management vs. Frequency Management was discussed.

In any management, the public perception should be taken into consideration. The Public should be involved in risk assessment.

There is a Federal initiative on green gas emission

There is no hard science to back up the low, medium, and high classification of risk.

Does the board ask for risk assessment? Should risk assessment be there as a part of integrity planning? The companies will choose the plan.

The CSA standard is only a tool, not necessarily the integrity management program.

The issue of corrosion monitoring should be dealt within the CSA document.

Colin McGovern presented the "Integrity Management of Acquired Pipeline System"
He noted that there should be a focus on integrity management.

It is necessary to transfer the knowledge to an operations team.

Typically a 4 hours course/discussion on a regular basis helps in the company.

Pitting corrosion is the cause of major failures.

To a question, Colin answered that there is no set budget for corrosion management.

The cost of inspection should be compared with the cost of replacement.

There are instances that the failures can be associated with the management change.

In some instances, the static state (when the pipeline is not operating) corrosion rate is high.

In some cases, we do not react quickly.

Real time corrosion monitoring will be beneficial.

- Risk assessment is only a part of Integrity management.

We can learn from other programs, e.g., the management of pressure vessels and related equipment (in Alberta – the ABSA programs).

If a company chooses to excavate pipeline locations, and show that the pipeline is in good shape, is it enough for the board?

Is digging a good method to show pipeline integrity?

An internal corrosion control program is based on science, mathematics, physics, and chemistry. Therefore it should undergo engineering scrutiny. It should be involve a professional engineer.

A detailed technical assessment is carried out before a digging operation is carried out. The technical assessment may include modeling and/or in-line inspection etc. But in many cases digging is the only way to obtain information on pipeline integrity.

How many digs do you need? It is a far-reaching question.

Alan Miller presented "PanCanadian Pipeline Risk Assessment Challenges for the Industry"
He noted that CSA standard is only a direction, not a plan.

The difficulties include:
- Probability of failure - the most difficult to quantify
- Location of next failure
- Modeling vs. Inspection

Asset inventory management resources are allocated on a consequence basis - not necessarily devoted to the numbers of incidents.

He noted that the probability of pit initiation might be associated to the probability of the presence of inclusions.

There are instances where the locations were predicted by flow models to be potential locations for corrosion - the pipeline was clear and vice versa.

Flow models are not reliable.

Corrosion was observed on the downhill section of pipelines.

Owner/user system is acceptable. But in order to be useful, a recognized organization such as CAPP should lead the initiative.

How should we decide to run the next risk assessment program?

Will there be an operating envelope?

There should be a red flag, (i.e., if the operating conditions change, a risk assessment should automatically be carried out).

There is generally a procedure that is followed for line suspension.

It will be appropriate to run the flow models to predict "what if" questions.

There should be a set range in which the pipeline should be operated.

Flow modeling is good for gas condensate but needs improvement to include oil properties.

How can one delegate responsibility within a company?

Where is the priority? High-risk areas or high-consequence areas?

Risk Assessment programs are run frequently, but it is difficult to catch the production changes in between the assessments.

There are techniques available for automation.

Flow models can be accurate.

If somebody constructs a house near the pipeline, does the risk assessment change?

Reality check: Not all upstream owners are present in this workshop. More participation is required in the future.

Dave Kwas presented an overview on, "Challenges by Small Diameter Pipelines to Inline Inspection Technologies"

In crude laterals, microbiologically influenced corrosion is a problem.

There are some unexplained internal corrosion problems.

In some cases, the monitoring methods have failed.

In one instance, the cost due to a failure is as high as $ 28 million. This cost does not include long term as well as indirect costs.

Public perception adds to the cost. Credibility is an issue.

MIC is an issue. Pit growth modeling is useful.

Karol Szklarz presented, "Inspection of Wet Sour Gas Pipelines"

In general, only the deepest pit per joint is analyzed from the ILI result. It is possible to obtain information on all pits.

If there are a large number of pits, the ILI may miss individual pits. Which pits are missed – the deepest or the shallow pits?

Sometimes the ILI indicates pits, but actual digging indicates no pits.

Weld beads can cause dead zones.

It is necessary that the ILI run does not disturb the scale that protects the pipeline. There were some instances where active corrosion was observed after the ILI run.

Inclusions can cause false information.

There is a need to increase the resolution of the ILI tool.

ILI is relatively easy to run in a liquid pipe, due to the velocity effect.

There is no experimental flow loop in Canada to test ILI tools.

Alan Miller presented, "Shallow Gas Pipeline Corrosion and Corrosion Control Strategy"
Condensed water does not lead to localized corrosion, but produced water leads to corrosion.

A 2-inch inspection tool not available.

Smaller pinhole leaks is the cause of many pipeline failures.

Failures generally occur at the first uphill rise.

Sands and clays are the main cause

How much of the gas is lost? Sometimes the leak goes undetected for about 6 months.

Can't use continuous inhibitor due to the location of the pipes.

Greenhouse gas is an issue.

Main Issues and Ideas

- The session was well attended, there was a good mix of people (producers, transmission, regulators, consultants, and others) ~ 100 attendees
- Ranking of spills
- Public perception that the pipelines are not safe
- Internal corrosion
  - sweet
  - sour
  - oil-emulsion
- No standard method for corrosion monitoring
- Role of flow modeling in the pipeline integrity program.
- Training and accreditation program for field operators/inspectors (is required?)
- Internal corrosion monitoring program
  - Guidelines needed (many companies will be interested)
  - Program should not only be developed, but should be used
- How to set a minimum pipeline integrity program
- Many times the integrity program is cost driven, not necessarily safety driven
- Sponsoring organization to look into the internal corrosion monitoring program
- CSA committees - not much representation from producers
- ILI program
  - tool/sensor failure
  - speed problem
  - still conservative
  - better length determination
  - use in liquid vs. gas pipeline.
- Industry should lead the way in establishing the internal corrosion control program
- Automation of corrosion monitoring/risk assessment
- Digging frequency
- Inspection tool for 2" pipelines

Main Outcomes

- A group was established to work on an Integrity Management program.
- Champions were identified.
- The Goal is to share the best practices.
- There will be a Task Force within CAPP.

BANFF/2001 PIPELINE WORKSHOP

Working Group 3: UPSTREAM PIPELINES

Co-Chairs: Dave Kwas (Pembina),Reg MacDonald (ExxonMobil), Alan Miller(PanCanadian)

April 9-12, 2001 Banff 2001 Pipeline Workshop

2001 Upstream Pipelines Today's Guide

- *"What's the Problem?" 8.30-10.00*
  - Current issues facing upstream PL's and downstream crude laterals
- *"How do we manage this?" 10.30-12.00*
  - What is the right approach to integrity management?
- *"How do we find it?" 1.30-3.00*
  - Inspection in small diameter pipe containing various substances and suffering various forms of damage is a challenge
- Other if time required 3.30-5.00

"What can we do here today which will help me tomorrow?"

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2001 Upstream Pipelines Desirable Outcomes - #1

- Identify specific problem areas so as to bring interested parties together to devise ways to minimize the problem(s).
- CSA Z662's Appendix on RA - Does Industry use it? How to apply it? Should it be modified? How to encourage a standard?
- "Pipeline Quality Management Programs" - Owner/User system acceptable? Should there be a group, CAPP or other, promoting this? Can an upstream producer earn a self-auditing status?

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2001 Upstream Pipelines Desirable Outcomes - #2

- Develop tools and practices to improve accuracy in small diameter inspection tools. Form a group to pursue improvements to accuracy in these tools.
- Define what Industry and Regulators find as acceptable inspection technologies for various forms of pipeline damage.
- What is an acceptable alternative to assessing integrity when Upstream Industry cannot justify an ILI or installation of corrosion resistant lining?
- Develop a decision tree for Inspection Technologies for Upstream Pipelines.

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1999 Working Group 4B: "Risk Management/Internal Corrosion - Producers"

- **Single session for Producers discussed risk management, relationships with regulators, predictive models, and field monitoring.**
- **New technologies are required for monitoring internal corrosion andeffectiveness of inhibitors with a focus on cost-effectively increasing thearea of coverage of corrosion monitoring tools.**
- **Performance metrics need to include a measure of the consequence.**
- **The consequence side of risk should be more actively considered andincluded in the measure ofperformance.**

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Progress from Earlier Pipeline Workshops

- '99 WS: CAPP/EUB task force working on a system for reporting of safety and environmental of consequences into the spill report forms. - progress report in this program
- '99 WS: New corrosion monitoring techniques are being used by a few, ie; electrochemical noise, FSM's, flush-mounted coupons, etc.
- '95 WS: Risk Assessment became more common
- '93 WS: CANMET Laboratory Test Method for CI selection in Sour Service
- Conclusion: Industry is changing as a result of the Banff Pipeline Workshop

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How we got started

- The Banff Pipeline conferences have provided an opportunity for people to meet and share ideas and common goals
- Upstream pipeline risk assessment (RA) was a topic for discussion in 1995
- Few upstream companies did structured RA at that time.

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What have we accomplished

- By 2000
  - Many companies have a RA process
  - There are numerous consulting and chemical supplier companies that can do RA for you
  - RA is non-mandatory appendix in CSA Z-662
  - There has been seminars, conferences and courses of risk assessment
- Risk Assessment is a common well understood practice in the upstream industry

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Why were we successful

- This change happened because the people involved in integrity management made it happen
  - It was not driven by upper management
  - It was not driven by regulators
- During this conference we will talk about the current issues and opportunities and where we want be in the future

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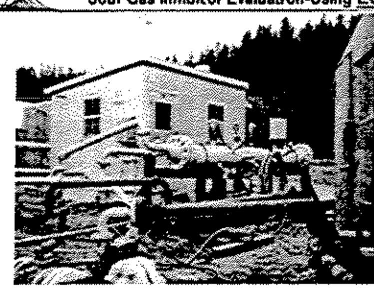
New Corrosion Monitoring Technologies Chevron Kaybob South Sour Gas Inhibitor Evaluation-Using ECN



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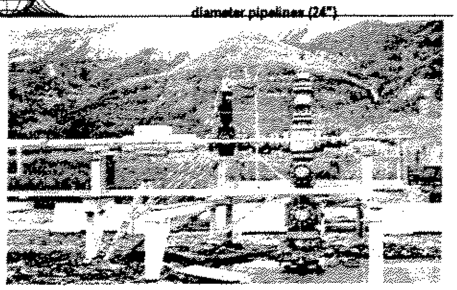
New Corrosion Monitoring Technologies Chevron Fort Liard FSM-IT Installation

Used on 8" piping - Can be used on small (2") to large diameter pipelines (24")



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2001 Upstream Pipelines "What's the Problem?"

- Regulator Focus and Plans - Bernie Frost, EUB (10min)
- Detailed Review of Alberta's Pipeline Failures - Reg MacDonald, EMC, Keith Cartmell, BP (10min)
- Current CAPP/EUB Initiative to Add Safety and Environmental Consequences to Spill Report Forms -, Ian Scott, CAPP (10min)
- Discussion - workshop session (60min)

"What are the challenges in upstream PL operation today?"

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2001 Upstream Pipelines
"What's the Problem?"

- Third Party hits - 1st CALL, penalties for non compliance
- EC - Regulatory requirement for CP, only rare disbonded coatings remain a problem, but small compared to IC
- IC - no "direct" regulatory requirement, how to enforce proper CI selection and application, inspection, then eventual replacement?

"Is the technology to combat IC adequate but not being used, or is the technology inadequate to do the job?"

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BANFF/2001
PIPELINE WORKSHOP

AEUB Surveillance Branch
Action Plan 2000-2004
Bernie Frost
Alberta Energy and Utilities Board

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Monitoring Industry Activity and Compliance Rates

» **Corrosion**

- Investigate 100% of pipeline corrosion failures.

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Operations Inspections

- Each Field Center to conduct pipeline operations inspections on multi-licensed systems, on 8 companies, that meet the following criteria:
  - Operators with high failure frequency.
  - Operators with questionable performance;
  - Operators of main trunk line systems.
  - Conduct two provincial pipeline operations inspections based on criteria mentioned above .

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Third Party Damage Investigations

- Investigate 100% of 3rd party damage incidents.
- Investigate causes/trends of 3rd party damage incidents and recommend strategies to reduce the number.

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Improve Industry and Public Awareness of Hazards Excavating near Pipelines

- Conduct 3rd party damage presentations to operators, contractors and public for education and awareness purpose.
- Encourage operators/contractors to obtain ground disturbance certification.

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FAILURE INCIDENTS

- Track increase/decrease in failures
- Track overall failure incidents compared to total pipeline lengths
- Analysis of historical data for failure frequency per 1000 kilometer indicates a 35% reduction over the past 11 years

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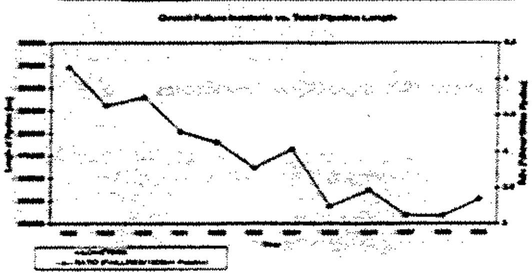
Failures Per 1000 Km Pipelines



FAILURE INCIDENTS

- Tracking pipeline failures by product
- This graph indicates failures byproduct as a percentage of total failures
- The trend shows natural gas incidents with a slight decrease. Most of the incidents aredirectly related to internal corrosion failures in the Medicine Hat area which are sweet, low pressure, and typically include produced water
- Multiphase product lines are showing a decrease in failure incidents over the past 10 year span.During this 10 year span the infrastructure has increased by 35%
- Water lines (fresh andproduced) are showing a decrease infailure incidents. This is due to materialselection such as non-metallicpipe or coatings andliner installations being used as corrosion barriers

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FAILURE INCIDENTS

- Crude oil remains constantwith external corrosion being the primary failure mechanism
- Sour gas failures have increased from 2%to 4% over the past 10 years. During this time the infrastructure has increased by 50%
- A number of new sour gas systems failingare a result ofcompanies not batch inhibiting their lines prior to commissioning service and others due to poorconstruction andoperating practices.

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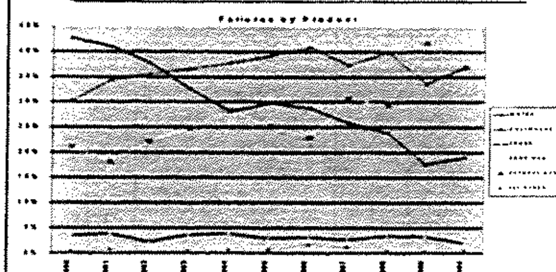
Failures By Product



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FAILURES BY CAUSE

- Internal corrosion failures increased 5% in the past year.
- Sensitive leak detection equipment has enabled industry to locate minor leaks that previously went undetected for longer periods of time.
- External corrosion failures are lower than historical.
- Third party damage (hits) are higher than historical.
- Construction damage failures are slightly higher than historical.

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FAILURES BY CAUSE

- Joint failures are higher than historical, however this infrastructure is increasing as non-metallic and coated pipe is being used more frequently to prevent internal corrosion
- Weld failures are lower than historical
- Over pressure failures are lower, due to more sensitive shut-in equipment being developed.
- Pipe failures are down as manufacturing improves.
- Valves and fitting failures are down as manufacturing improves
- Other failures are up due to failures not being dug up to determine failure cause.

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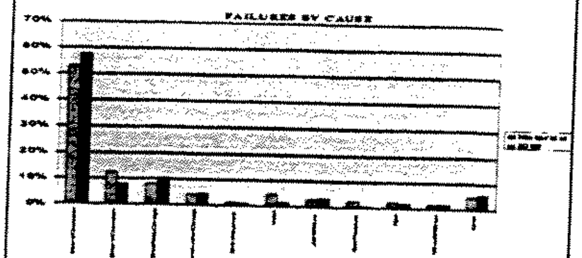
Failures By Cause



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DAMAGE BY OTHERS GRAPH

- This graph indicates a historic view of the number of pipelines hit each year
- The Oil and Gas industry is the leader in contact damage to pipelines at 80%, landowners and other construction activities account for the other 20%

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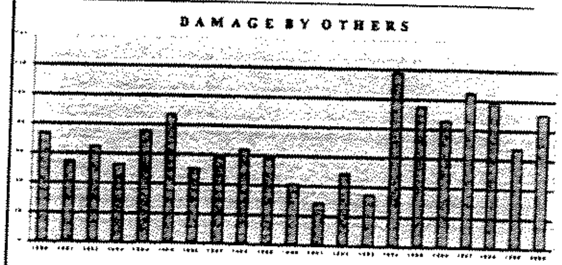
Damage By Others 1980 To Present



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FRONTLINE STAKEHOLDER AWARENESS CORROSION GUIDE

- EUB staff have developed a Corrosion Gide for use by Field Surveillance Inspectors to effectivelyand consistently address corrosion failures.
- Enforcement action has been developed todeal with industry when a corrosion failure occurs. "U" minor "M" major "S" serious.

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CORROSION INSPECTION SUMMARY

- Our action plan dictates all corrosion failures be addressed. The companies mitigationplans documentinghow they will prevent further corrosion failures must be reviewed and evaluated. These fdlow-up reviews/evaluations may take placewithin 12 months of the occurrence.
- When a failure occurs the companywill be instructed to look at the mitigation program of the failed pipeline and the rest of thepipeline system.
- All systems operating underEUB jurisdiction not monitoring for corrosion potential shall be subject to the EUB's escalating consequences of enforcement action as outlinedin IL 99-4.

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Closing

- The direction Field Surveillance Branch is taking as you can see by our operating plan for 2001-2004, pipeline corrosion failures and pipeline integrity is our number one goal.
- We appreciate the opportunity to attend the Banff/2001 Pipeline Workshop and the opportunity to give industry an idea of where we're heading as a regulatory board.
- Thank you and enjoy the rest of the workshop.

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Presentation to
2001 Banff Pipeline Integrity Workshop Group3

"Upstream Pipelines: Inspection, Corrosion and Integrity Management"

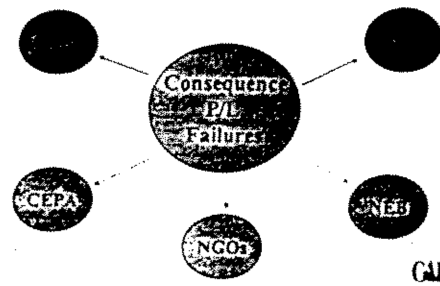
April 11, 2001

Ian Scott
Manager
Northern Canada and Pipelines

CAPP

Consequence of P/L Failures

- CAPP established Task Force spring 2000



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Historical Perspective - Workshops

• First	June 1993	Pipeline Lifeline
• Second	June 1994	Pipeline Lifecycle
• Third	October 1995	Managing P/L Integrity
• Fourth	April 1997	Managing P/L Integrity, Planning for the Future
• Fifth	April 1999	Managing P/L Integrity, Technologies for the New Millenium
• Sixth	April 2001	Managing P/L Integrity, A Workshop for Sharing Technology and Experience

CAPP

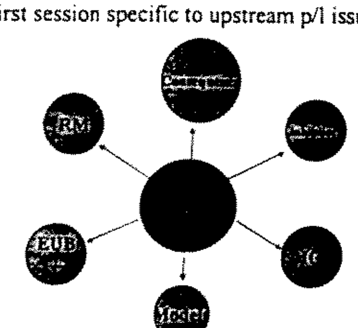
Consequence of P/L Failures - Objectives

- Develop EUB IL which defines
  - Minor, moderate & severe p/l failures
    - environmental damage/impact
    - public safety
- Revise EUB Incident report form
  - environment
  - safety
- address u/s p/ls initially

CAPP

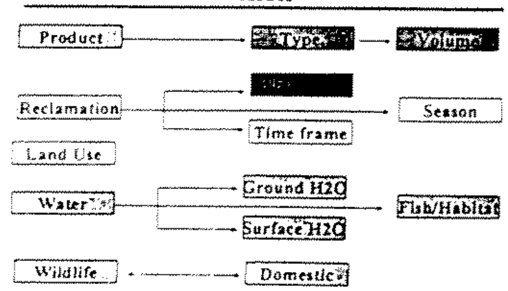
1999 Workshop - U/S Risk Management/IC

- First session specific to upstream p/l issues



CAPP

Consequence of P/L Failures - Environmental Issues



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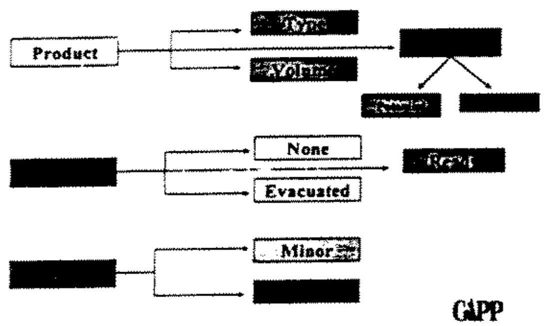
Consequence of P/L Failures - Public Safety Issues



CAPP

Consequence of P/L Failures - Next Steps

- Task Force - soliciting comments
  - EUB & NEB
  - CEPA
  - APESC
- EUB/Industry to pilot "system" for one year
- Review with NGOs
- Amend as necessary
- EUB issue Interim Directive apply all releases
  - Pipeline Act
  - Oil And Gas Conservation Act.

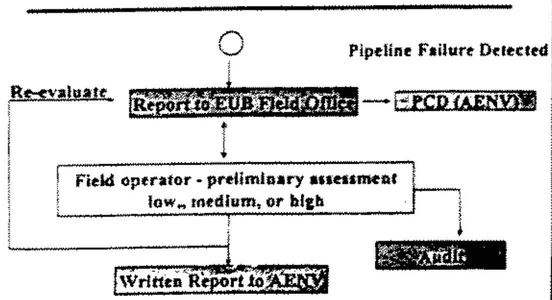
CAPP

Consequences of Pipeline Failures Definitions - Environmental

- **Low**
  - requires short-term remediation
  - unlikely to decrease wildlife populations or habitat
  - surface water & designated/locally important areas not affected by the release
- **Medium**
  - requires more intensive remediation.
  - may have affected wildlife habitat but are unlikely to decrease wildlife populations
  - surface water & designated/locally important areas not affected by the release
- **High**
  - requires long-term remediation, or in some cases complete remediation may not be possible
  - may permanently damage the affected area & have an adverse effect on wildlife populations
  - Surface water and designated/locally important areas may be affected by the release

CAPP

Consequence of P/L Failures - Process



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Banff Pipeline Workshop
April 11, 2001

Framework for Integrity Management of Internal Pipeline Corrosion

James Ferguson
CorrosionWATCH Inc.

Agenda

- Integrity Management Background
- Integrity Management Today
- Application of CSA Z662-99 Risk Management to Integrity Management
  - Definition of Terms
  - The Process of Risk Management
  - Frequency Analysis
- Summary

Integrity Management Background

"Federal regulations and industry safety codes and recommended practices provide guidelines for the safe design, operation and maintenance of pipelines, but pipeline operators still have to continually monitor and assess the condition of their pipelines to prevent them from being seriously degraded by things like corrosion, damage from outside forces, which includes excavating equipment, and operational wear and tear."

– Dr. John F Kletner, NTSB Pipeline Safety Hearing, Washington, DC on Nov 15, 2000

Integrity Management Today

- Upcoming US regulatory requirement
  - API Standard 1160 'Managing Pipeline System Integrity' (in progress)
  - New OPS rule requiring integrity management programs expected in Oct 2001 (OPS is the DOT Office of Pipeline Safety)
- Non-mandatory guideline in EUB ID 99-7
  - CSA Z662-99 includes 'Guideline for Risk Assessment of Pipelines'
- NEB Onshore Pipeline Regulations, 1999
  - Section 40. 'A company shall develop a pipeline integrity management program'
  - Non-compulsory guidelines

Application of CSA Z662-99 Risk Management Process to Integrity Management

Definition of Terms

– From CSA Z662-99, B3.1

Risk management - the integrated process of risk assessment and risk control.

Risk assessment - the process of risk analysis and risk evaluation.

Risk analysis - the use of available information to estimate the risk, arising from hazards, to individuals or populations, property, or the environment.

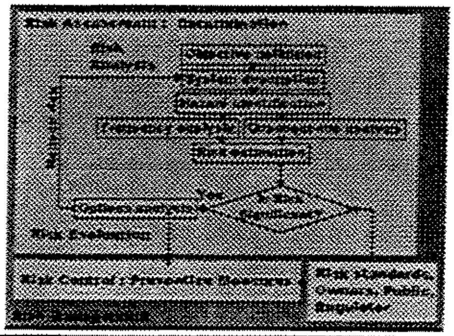
Risk estimation - the process of combining the results of frequency and consequence analysis to produce a measure of the level of risk being analyzed

Risk evaluation - the process of judging the significance of the absolute or relative values of the estimated risk, including the identification and evaluation of options for managing risk.

Risk control - the process of decision-making for managing risk, and the related implementation, communication, and monitoring activities required to ensure the continuing effectiveness of the risk management process.

The Process of Risk Management

– From CSA Z662-99, Appendix B



Frequency Analysis for Internal Corrosion Integrity Management

- Use qualitative measurement for frequency analysis
  - Apply "Judgement of experienced and qualified engineering and operating personnel, based on known conditions."
    - From CSA Z662-99, B5.2.4.2(d)
- Rational:
  - Conditions that lead to internal corrosion of pipelines can be identified and ranked using scientific models based on available data of material properties, product composition, and process conditions

Summary

- Regulation of Integrity Management is approaching
- CSA Z662-99 Risk Management process framework can be used to manage internal pipeline corrosion

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INTEGRITY MANAGEMENT OF ACQUIRED PIPELINE SYSTEMS

Colin McGovern,
Anderson Exploration Ltd.

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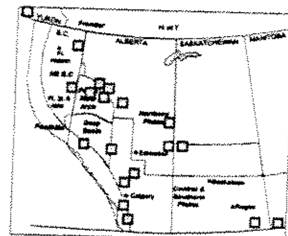
AXL Operations

- Six Districts
- 150 Field Locations
- > 5000 Pipelines
  - Sweet Gas
  - Sour Gas
  - Sweet Oil
  - Sour Oil



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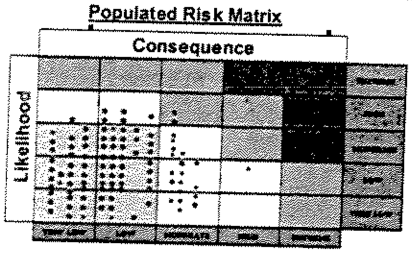
Populated Risk Matrix



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AXL Risk Based Assessment Intervals

Inherent Risk	Assessment Interval
High Risk	Redesign
Medium-High Risk	1 Month
Medium Risk	1-2 Years
Low Risk	3-5 Years

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ASSESSMENT OF PIPELINE SYSTEMS

- New Systems
- Existing Systems
- Acquired Systems

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ASSESSMENT OF PIPELINE SYSTEMS

- New Systems
- Existing Systems
- Acquired Systems

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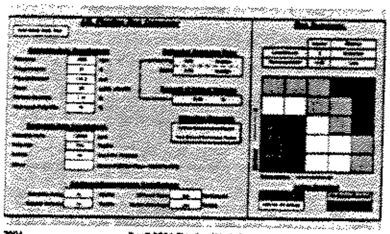
New Systems



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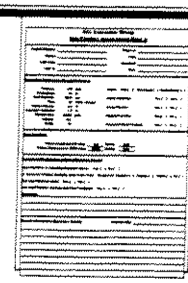
New Pipeline Assessment Report



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ASSESSMENT OF PIPELINE SYSTEMS

- New Systems
- Existing Systems ⇦
- Acquired Systems

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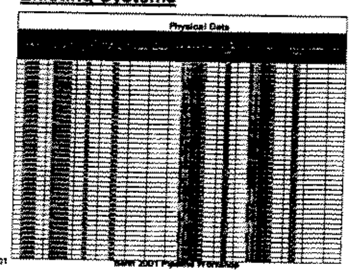
Existing Systems



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ASSESSMENT OF PIPELINE SYSTEMS

- New Systems
- Existing Systems
- Acquired Systems ⇦

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Acquired Systems

Assessment Order:

1. Failure History
2. Inhibition Programs
3. Operating Conditions
   - Sour Gas
   - Sour Oil
   - Sweet Gas
   - Sweet Oil

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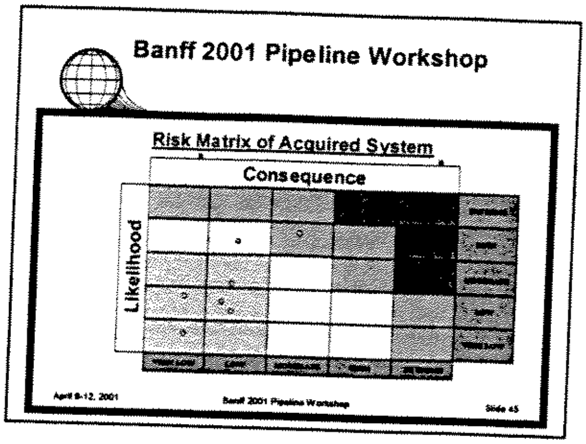
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Risk Matrix of Acquired System
Consequence
Likelihood
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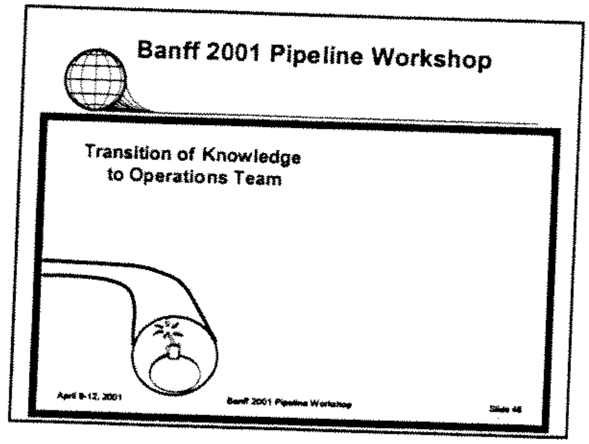
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Transition of Knowledge
to Operations Team
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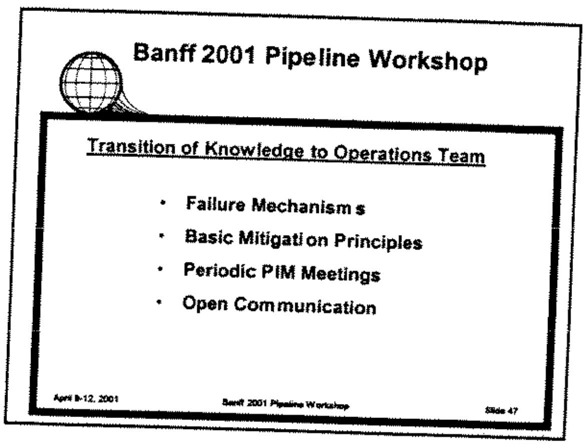
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Transition of Knowledge to Operations Team
• Failure Mechanisms
• Basic Mitigation Principles
• Periodic PIM Meetings
• Open Communication
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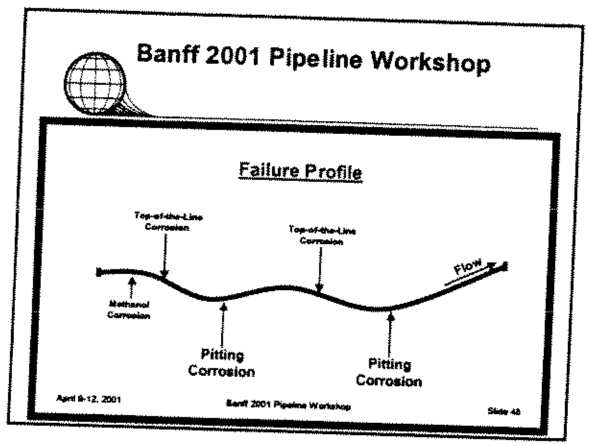
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Failure Profile
Top-of-the-Line Corrosion
Top-of-the-Line Corrosion
Flow
Methanol Corrosion
Pitting Corrosion
Pitting Corrosion
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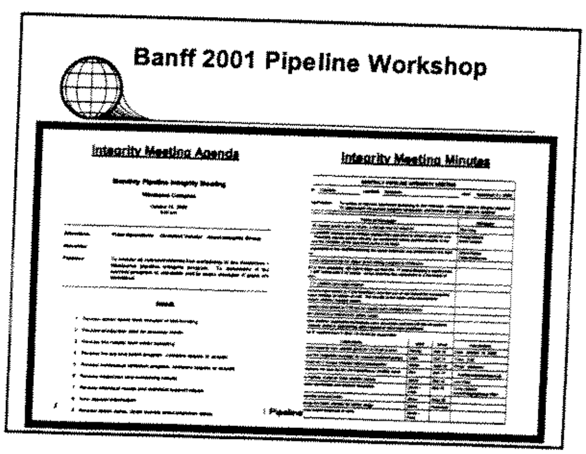
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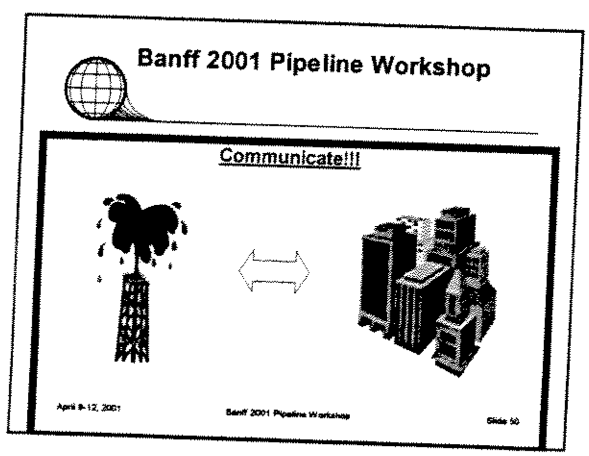
Integrity Meeting Agenda
Integrity Meeting Minutes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Communicate!!!
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PanCanadian Pipeline Risk Assessment Challenges for the Industry

- Probability of failure the most difficult to quantify
- Location of the next failure
- Modeling versus inspection
- Asset Inventory Management
- Resources allocated on consequence basis not necessarily devoted to numbers of incidents

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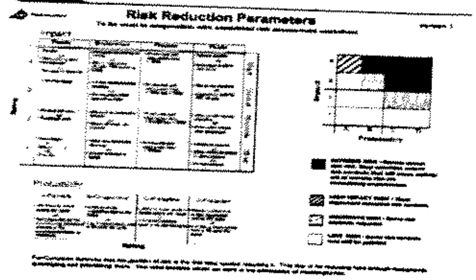
PanCanadian Pipeline Risk Assessment



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PanCanadian Pipeline Risk Assessment

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PanCanadian Risk Assessment Worksheet

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PanCanadian Pipeline Risk Assessment Issues for Discussion

- Probability of failure the most difficult to quantify

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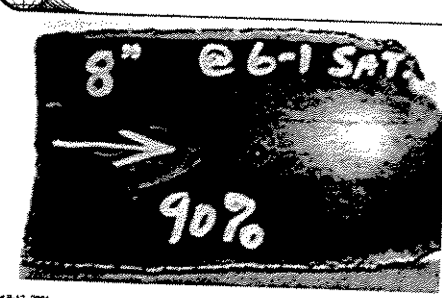
Probability of failure the most difficult

Localized Corrosion Defect in Nisku Multiphase



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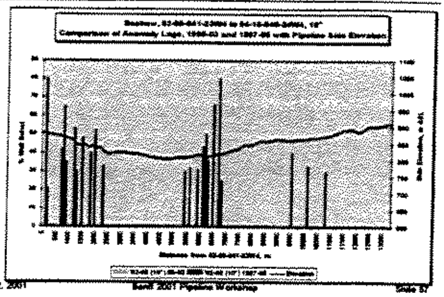
A. Miller - PanCanadian

Probability of failure the most difficult

1995 and 1997 MFL logs on Main 10" Flowline



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PanCanadian Pipeline Risk Assessment Issues for Discussion

- Location of the next failure
- Probability of inclusions as the site of corrosion pits-Consortium subject?
- Modeling versus inspection
  - » CorrOcean- Nguyen Bich

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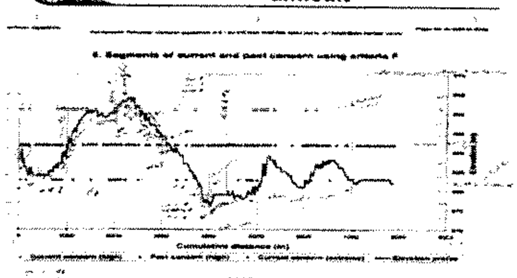
Probability of failure the most difficult



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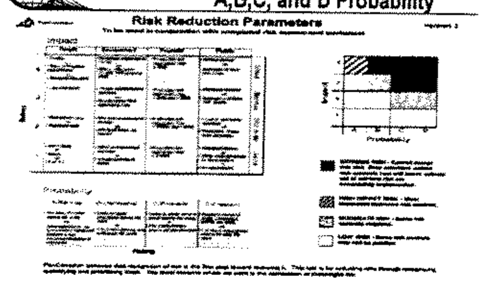
PanCanadian Pipeline Risk Assessment A,B,C, and D Probability

Risk Reduction Parameters



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PanCanadian Pipeline Risk Assessment Issues for Discussion

- Inventory

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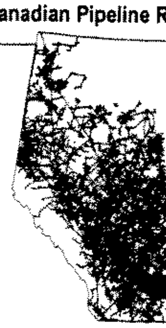
PanCanadian Pipeline Risk Assessment



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A. Miller - PanCanadian

PanCanadian Pipeline Risk Assessment

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PanCanadian Pipeline Risk Assessment
How often should we be repeating RA's?

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OWNER/USER AUDIT

- "Pipeline Quality Management Programs"
- Owner/User system acceptable? Should there be a group, CAPP or other Industry group, promoting this? Can an upstream producer earn a self – auditing status?

April 9-12, 2001 — Banff 2001 Pipeline Workshop — Slide 65

Pipeline Quality Management Program

Pipeline Quality Management Program

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PanCanadian Pipeline Risk Assessment
Issues for Discussion

- Resources should be allocated on consequence basis not necessarily devoted to numbers of incidents..or both?
- How often should we be repeating RA's?
- Suggestions for managing large asset inventories?
- Define A,B,C, and D (Probability in Risk Matrix)
- Industry managed Pipeline Quality Management Programs

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BANFF/2001 PIPELINE WORKSHOP

Challenges by Small Diameter Pipelines to Inline Inspection Technologies

"How Do We Find It?"

April 9-12, 2001 Banff 2001 Pipeline Workshop

Presenters

- Dave Kwas - Pembina - Crude Laterals
- Karol Szklarz - Shell - Sour Gas Pipelines
- Alan Miller - PanCanadian - Oilwell Effluent Pipelines
  - Shallow Gas Pipelines

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Getting Started

- Probability of failure x impact of failure
- As pipeline service increases, probability of failures due to corrosion increases
- Are there any corrosion defects present?
- After inspection, what causes risk to be reduced?
- When to re-inspect?

April 9-12, 2001 Banff 2001 Pipeline Workshop Slide 70

Crude Laterals - Pembina Pipeline Corporation

- 4400 km. (52%) are less than 10" in diameter
- Various operating / corrosion challenges
- Pipeline Operators' priorities
- Bottom line

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History

- Aerial / ground patrols, geotechnical, leak surveys
  - third party damage
  - ground movement
  - leakage
- Smart tool logging, CP/coating surveys, product quality
  - materials / construction defects
  - coatings
  - fatigue / cracking
  - internal / external corrosion
- Corrosion monitoring methods for the most part failed

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Integrity Maintenance

- No leak objective
- Periodic internal inspections
- Defect assessment using fitness - for - purpose criteria
- Selective repairs
- Data management

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Conclusion

- Smart tool accuracy
- Risk of leaving defect in the pipeline
- Rate of defect growth
- All must be considered when making pipeline repairs

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What's Next

- Other cost effective ways of determining integrity of a short, small diameter pipeline
- When are digs absolutely necessary
- Is corrosion growth / life prediction models next?
- Where is internal logging headed?

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INSPECTION OF WET SOUR GAS PIPELINES

Karol E. Szklarz
Shell Canada Limited

Prepared for Banff 2001 Pipeline Workshop

CURRENT SITUATION

- Almost exclusively mag flux leakage (MFL)
- Low to medium resolution tools for internal/external corrosion pit depths
- Conducted as frequency- or condition-based
- Cornerstone of pipeline integrity programs (proactive & reactive)

CURRENT SITUATION (cont'd)

- Run reliability (with no problems) is 70%+
- Medium resolution ~ +/- 10% of wall thickness for "normal" aspect ratio
- Otherwise resolution is +/- 20% of wall
- Data is electronic and hardcopy; hardcopy still used a lot
- Reasonable local supply of contractors

ISSUES

- Tool/sensor failures and speed problems are still significant
- Where pits are more numerous can miss individual pits
- Ghost pits
- Weld beads can cause small "dead zone"

ISSUES (cont'd)

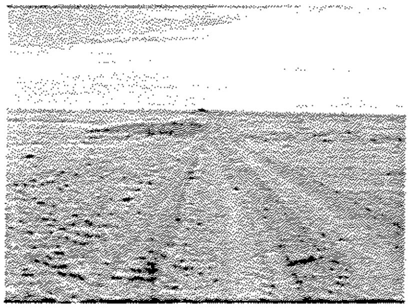
- Length and width measurements are still very conservative leading to conservative strength assessments
- Can cause initiation of corrosion by removing protective scales (need batch inhibitor)
- Still need dig RT/UT data to "calibrate" run
- No crack detection capability

FUTURE

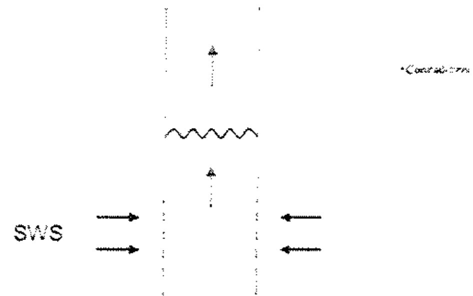
- Increased reliability in data collection
- Better software to analyze all pits above a threshold deep (underway)
- Higher resolution tools
- Better length determination so that realistic pit interaction assessments can be done (underway)
- Calibration by pull through on all pipe OD/ thickness combinations (underway)
- New tools for finding and sizing cracks

Internal Corrosion Initiated at Wheel Tracks Made by In-Line Inspection Tool

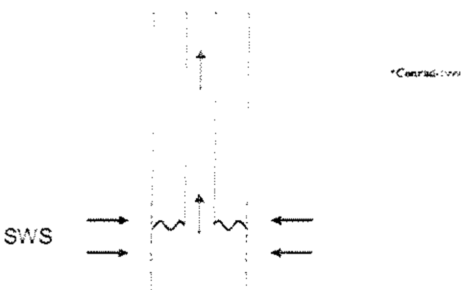
Shallow Gas Pipeline Corrosion and Corrosion Control Strategy

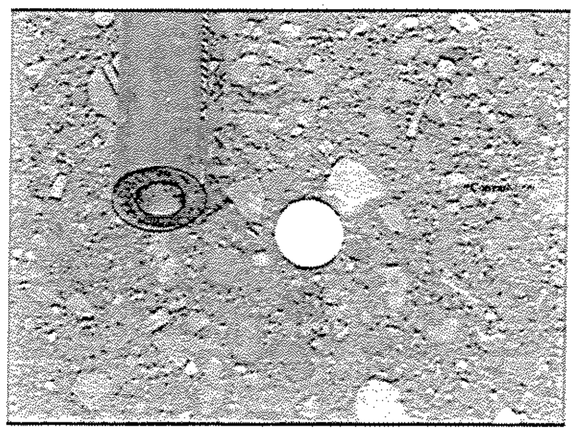


SWS well - loaded condition



Well with siphon string

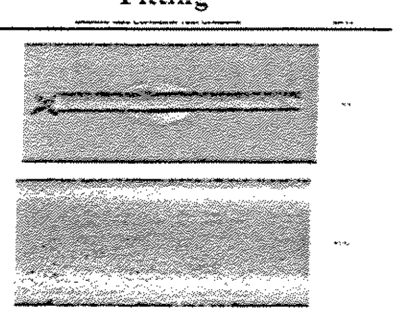


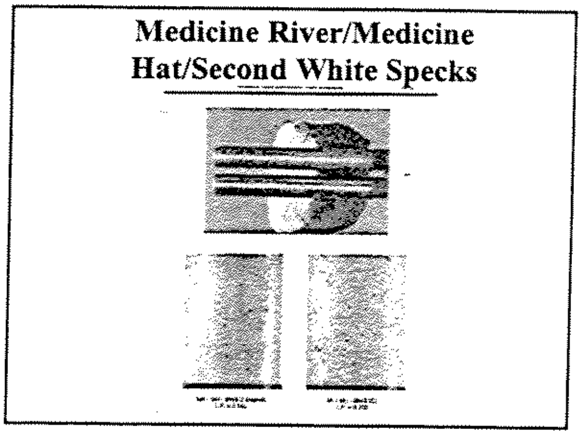


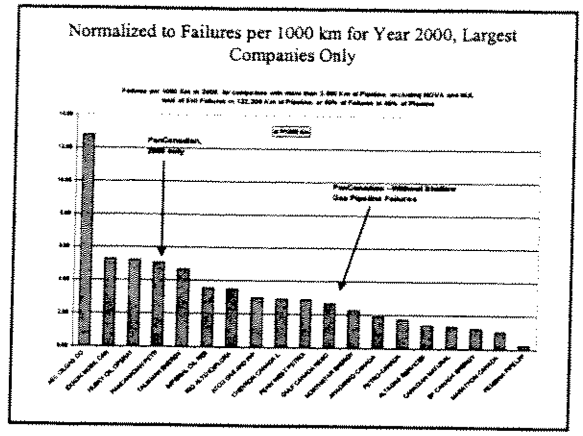
Formation Waters from Shallow Gas Zones

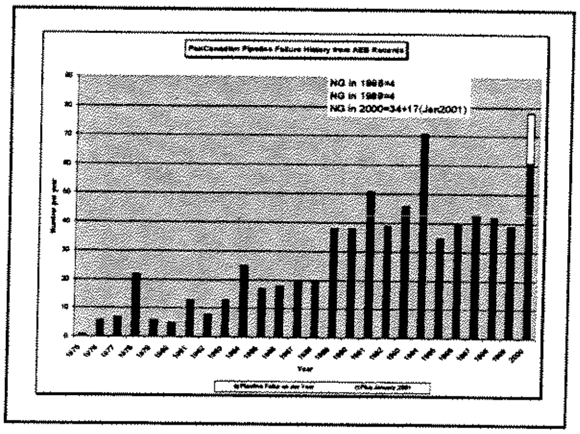
Location / Test	Condensed Pipeline	BellyRiver Foremost	BearPaw	[illegible]	Milk River	Belly River	Medicine Hat	Second Whitespecks
TDS (mg/L	2.1	10200	5220	5410	1810	8110	6810	11000
PPCO2, %	0.1	0.05	0.2	0.1	0.1	0.05	0.1	0.05
Localized Corrosion (0-1)	0	0.64	0.55	0.701	0.11	0.28	0.2	0.51
General Corrosion,mpy	0.5	2.7	2.2	2.6	0.9	2.1	1.9	0.9

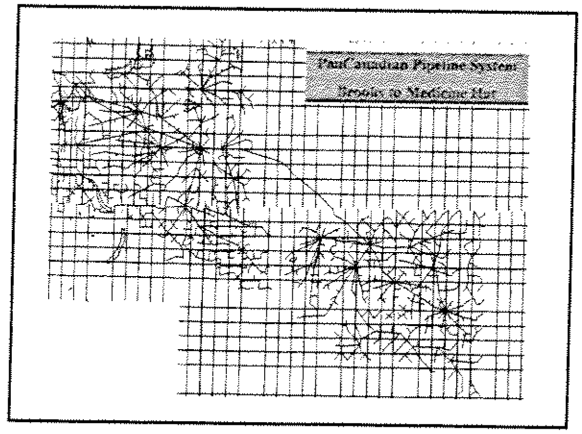
Condensed Water-No Localized Pitting

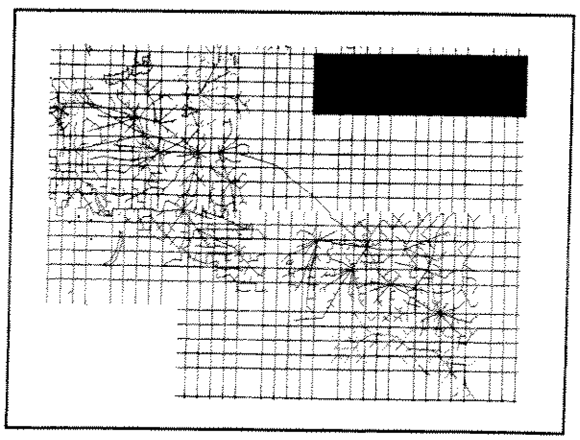


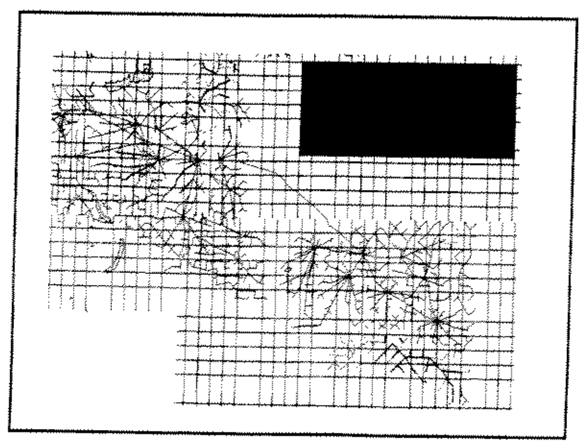

Medicine River/Medicine Hat/Second White Specks

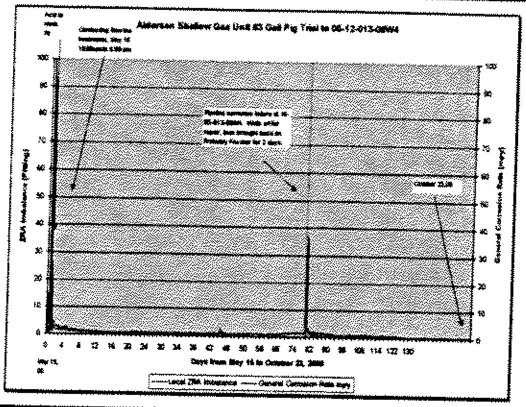

Normalized to Failures per 1000 km for Year 2000, Largest Companies Only
PanCanadian, 2000 only

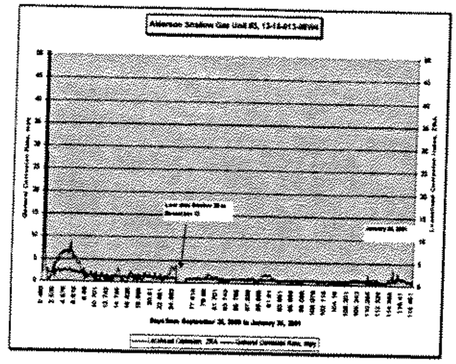

NG in 1998=4
NG in 1999=4
NG in 2000=34+17(Jan2001)


PanCanadian Pipeline System
Brooks to Medicine Hat





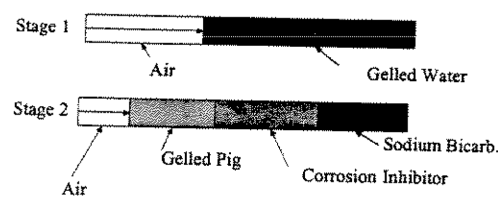




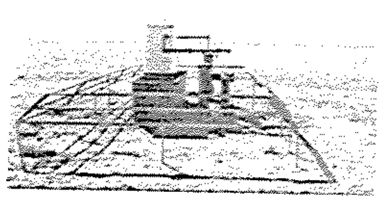
Pipeline Corrosion Control Options

Case	Description
1	Repair and Replace over time
2	Mechanical Pig Equipment
3	Chemical Pig 2"/mechanical pig group flowlines
4	Chemical Clean 2", Install Wellsite flowdrips at siphon string wells
5	HDPE Liners or FibreSpar (FRP reinforced, HDPE Liners)

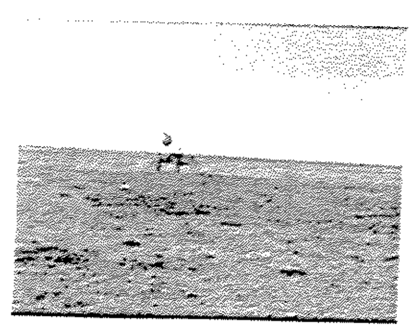
Corrosion Mitigation- Polymer Train



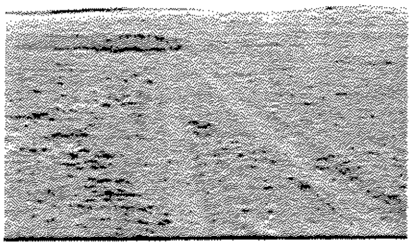
FlowDrip and Dog Dish



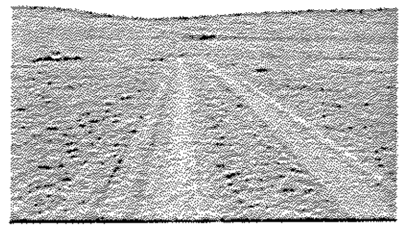
08-10-013-08W4 Well and Leak Site



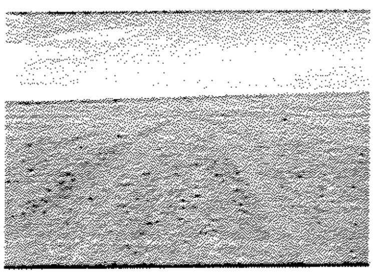
06-26-013-08W4 Flowline Leak Site



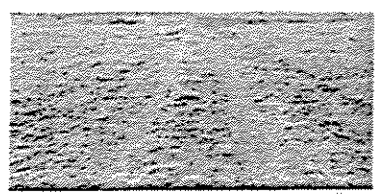
06-32-013-08W4 Flowline Leak Site



06-07-013-08W4 Flowline Leak Repair



13-29-013-08W4 Flowline Leak Repair Site



Managing Pipeline Integrity: Upstream Pipelines: Inspection, Corrosion & Integrity Management Banff/2001 Pipeline Worksh

April 11, 2001 8:30 a.m. - 5:00 p.m.

	Company	Name	Phone	E-mail	Signature
1	CORROSION SERVICE	TREVOR PLACE	(403) 233-2601	tplace@corrosionservice.com	
2	PEMBINA PIPELINE CORP	PETE DONNELLY	780 542-5341	pdonnell@pembina.com	
3	EUB	RON CHARLESWORTH	403 340 5429	ron.charlesworth@gov.ab.ca	
4	EUB	EARL LEONARD	780·460·3806	earl.leonard@~~eub~~.gov.ab.ca	
5	TCPL	TRENT VAN EGMOND	403-920-5993	trent_van_egmond@transcanada.com	
6	U.S. Minerals Management Service	Bob Smith	1-703 787 1580	robert.w.smith@mms.gov	
7	U.S. MINERALS Mgt. Service	PAUL E MARTIN	(703) 787-1626	PAUL.MARTIN@MMS.GOV	
8	Pembina Pipeline	Dave Kwas	(403) 231-7508	dkwas@pembina.com	
9	Talisman Energy	Bob Shapka	(403) 237 1953	bshapka@talisman-energy.com	
10	Positive Projects	Maury Dumba	(403) 231-1650	maury.dumba@positiveprojects.com	
11	Positive Projects Inc.	LEE GREANYA	(403) 286-4236	lee.greanya@positiveprojects.com	
12	Positive Projects	Gerry Wilkinson	(403) 235-1650	gerry.wilkinson@positiveprojects.com	
13	AEUB ~~Bernie Frost~~	Bernie Frost			
14	Broadsword Corrosion Eng Ltd	Patrick J. Teevens	(403) 202-2060	pteevens@telusplanet.net	
15	KOCH PIPELINES CDN	NEIL S. HAY	(403) 716-7670	HAYN@EPDIVISION.COM	
16	CORRPRO CANADA INC	GRANT FIRTH	(780) 447-4565	grant.firth@corrpro.com	
17	~~KELLY MABBOTT~~ SKYSTONE ENG.	~~Ke~~ Kelly MABBOTT	403 216-3485	kmabbott@skystone.ca	

18	COLT ENG'G. ~~Darius Boucher~~	DARIUS BOUCHER	403-259-1888	~~Dar~~ ~~dc~~ BOUCHER.DARIUS@COLTENG.com	[illegible]
19	AEUB	Dave Grzyb	403 297 8432	dave.grzyb@gov.ab.ca	NWGrzyb
20	MAYA DATABASE INC	BRUNO ROMERO	403-263-4848	mayacofe@cadvision.com	Bruno Romero
21	ALLIANCE PIPELINE	DARYLL WENDLAND	780-518-7622	wendlad@alliance-pipeline.com	D. Wendland
22	Canadian Hunter Exploration	Allan Hobbis	780 539-3007	allan.hobbis@chel.com	[illegible]
23	Minh Ho	National Energy Board	(403) 299-2762	mho@neb.gc.ca	MH
24	LEONARD LOZOWY	ALTAGAS UTILITIES	(780) 980-7313	llozowy@agutl.com	[illegible]
25	JOHN CHASE	HUNTER McDONNELL	780 436 4400	JCHASE@HMPSI	[illegible]
26	Imperial Oil	AL FORTH	905-689-6621	al.forth@esso.com	[illegible]
27	HCI CANADA	BARRY NICHOLS	403 391-1335	bnichols@hciww.com	[illegible]
28	Nu-Tree M'ment	Bruce Fowlie	403 2510387	fowlieb@cadvision.com	[illegible]
29	RUSSELL NDE SYSTEMS	Jim Yukes	780 468 6800	jyukes@russelltech.com	[illegible]
30	BAKER ATLAS	TIM HETU	403-350-1770	tim.hetu@bakeratlas.com	[illegible]
31	4/J VENTURES LTD	BERT JOHNSON	403 686 8412	jmail@telusplanet.net	[illegible]
32	ALL TEST INSPECTION	RON PYETTE	403 362 5757	rpyette@telusplanet.net	[illegible]
33	Tuboscope	Todd Ring	780 955 8611	tring@tuboscopepls.ab.ca	[illegible]
34	~~Ramesh~~ RAE INSPECTION SERVICE	Ramesh Singh	780-449-2401	ramesh@raeinspection.com	[illegible]

35	Canusa-CPS	Mark William	403-218-8207	mark.william@shawind.com	[illegible]
36	DENSO NORTH AMERICA INC.	GLENN MACINTOSH	780.910.1212	glenn@densona.com	[illegible]
37	KTA-Tator (Canada)	LINDA GRAY	780-440-9391	lgray@kta.com	[illegible]
38	HCI Canada	David Dan	403 720 5662	ddan@hciwld.com	[illegible]
39	IMPERIAL OIL RESOURCES	DARRYL SHYIAN	780-639-5813	darryl.shyian@iol.sprint.com	[illegible]
40	BP Canada Energy Com.	Bob Longpre'	403-233-1230	longprrl@bp.com	[illegible]
41	BP CANADA ENERGY Co.	VINCE KITTELSON	403-233-6359	kittelvw@bp.com	[illegible]
42	Pengrowth Corp	Phil GAUTHIER	780-733-7109	Philga@pengrowth.com	[illegible]
43	Greenpipe Industries	Matt Gomke	403-260-8783	matthewgomke@greenpipe.com	[illegible]
44	Baseline Tech.	Ken Clark	403 266 3800	KenC@baselinetech.com	[illegible]
45	CorrosionWATCH	JAMES FERGUSON	403 572 2200	JamesFerguson@CorrosionWATCH.com	[illegible]
46	CATHOLIC UNIVERSITY OF RIO	IVANI BOTT	55(21) 5400703	bott@mailz.mc.puc-rio.br	
47	RWDI WEST INC.	IAN DOWSETT	(403) 232-6771	IAN.DOWSETT@RWDIWEST.COM	[illegible]
48	Dynamic Risk Assessment	Glenn Yuen	403 547 8638	glenn.yuen@dynamicrisk.net	[illegible]
49	Global Thermoelectric	Garner Meszaros	403 204 6163	garnerm@globalte.com	[illegible]
50	KOMEX INTERNATIONAL	Fred Claridge	403-247-0200	fclaridge@calgary.komex.com	[illegible]
51	Corrpro Canada Inc	Dan Powell	403-235-6400	dan.powell@corrpro.ca	[illegible]

52	LYLE GERLITZ	JLG ENG.	(403) 547-7136	lgerlitz@telusplanet.net	[signature]
53	RAY PRICE	BP CANADA	(403) 233-6351	pricere@bp.com	[signature]
54	Alex Petrusev	Corrosion Service Comp	(403) 233-2601	apetrusev@corrosionservice.com	[signature]
55	Scott Arndt	Husky Oil	(780) 871-6553	Scott.Arndt@husky-oil.com	[signature]
56	Colin McGovern	Anderson Exploration	(403) 232 7019	mcgovec@AXL.ca	[signature]
57	KEN KOVACS	SHELL CANADA	(403) 932-8316	KEN.KOVACS@SHELL.CA	[signature]
58	DARYL BAXANDALL	CorrOcean Canada	(403) 286-0606	daryl@corrocean.com	[signature]
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63	S. Papavinasam	CANMET/MTL	613-947-3607	spapavin@nrcan.gc.ca	[signature]
64	Jenny Been	CANMET/MTL	613-992-4252	jbeen@nrcan.gc.ca	[signature]
65	Mimoun ELBOUJDAINI	CANMET/MTL	(613) 995-3971	melboujd@nrcan.gc.ca	[signature]
66	Ian Scott	CAPP	(403) 267-1132	scott@capp.ca	[signature]
67	KEITH CARTMELL	BP CANADA	403 233 6324	CARTMELK@BP.COM	[signature]
68	Chris Horkoff	AEC Oil & Gas	(403) 502-3382	chrishorkoff@aec.ca	[signature]

69	Neocorr Engineering	Allan Bouwers	403-531-1926	allan@neocorr.com	
70	Pierce Consulting Ltd	Chris Pierce	403-281-8627	cpierce@telusplanet.net	
71	Shu C Lee	EUB	403-297-3367	shu.lee@gov.ab.ca	
72	Greenpipe	Graeme King	403 260 6714	graemeking@greenpipe.com	
73	Union Gas Ltd / Ontario	Gord Phipps	519-683-4468	gphipps@uniongas.com	
74	Corrpro Canada Inc.	Zane Reinhart	(403) 235-6400	zane.reinhart@corrpro.ca	
75	Invicta [illegible]	Dave Black	403-288-8005	BlackDG@[illegible].NET	
76	Crit Engineering	Art Harms	403 259-1873	harms.art@colteng.com	
77	ISOCAN	Richard Edelmuth	(403) 253-0929	edelmuth@telusplanet.net	
78	Nova Chemicals	Mary Gale	403-314-7491	galem@novachem.com	
79	Alex Afaganis	Camrose Pipe	780 672-3116	afaganis@campipe.com	
80	Nigel Alvarez	Greenpipe Ind.	(403) 260-6703	nalvarez@greenpipe.com	
81	Battelle	J. Bruce Nestleroth	614 424 3181	nestlero@battelle.org	
82	Canspec Group Inc	Brian Paradis	780-490-2445	bparadis@canspec.com	
83	Corrpro Canada Inc.	Dennis Zadery	780-447-4565	dennis.zadery@corrpro.ca	
84	National Energy Board	Josef Kopec	(403) 299-3690	jkopec@neb.gc.ca	
85	Univ of Waterloo	Roy Pick	519 888 4567	rjpick@uwaterloo.ca	

86	Corrpro Canada Inc	Doug Doran	780-447-4565	doug.doran@corrpro.ca	[illegible]
87	Morrison Scientific	Guy Desjardins	(403) 262-8160	guy@morrisonscientific.com	[illegible]
88	ALL TEST INSPECTION	RON PYETTE	403-362-5757	rpyette@telusplanet.net	[illegible]
89	CANSPEC	TED HAMRE	780 490 2432	thamre@canspec.com	[illegible]
90	UNIVERSITY OF WATERLOO	DUANE CRONIN	519 888 4567 x 2682	dscronin@engmail.uwaterloo.ca	[illegible]
91	CC Technologies	John Beavers	614 761 1214	jbeavers@cclabs.com	[illegible]
92	HUNTER MCDONNELL PIPELINE SERVICES	Denene Geissler	~~780~~-436-4400 ext. 107	d-enene@hmpsi.com	[illegible]
93	ROSEN CANADA	[illegible] STELMACHUK	403-265-1151	rosencan@[illegible]	[illegible]
94	PII North America	Christine Rubadeau	713-849-6346	rubadeauc@PII_USA.com christiner@evi.net	[illegible]
95	Imperial Oil/ExxonMobil	Reg MacDonald	403 237 2548	reg.w.macdonald@email.mobil.com	RM.
96					
97					
98					
99					
100					

Working Group 3: Upstream Pipelines Inspection, Corrosion and Integrity Management

Co-Chairs: Dave Kwas (Pembina), Reg MacDonald (IOR), Alan Miller (PCP)

Highlights

- 95+ Attendees
- Internal Corrosion
- EUB Enforcement Ladder
- CAPP/EUB - Spill Report Form
- Corrosion Monitoring
- Integrity Management Program

Main Outcome

- Group Established to Work on Integrity Management Program
- Champions Identified
  - **Col in McGovern**
  - **Ra y Price**
- Goal: Share the Best Practices
- Task Force within CAPP

Working Group 4 – Construction, Repair, and Maintenance

Tuesday, April 10, 2001, at 10:30 a.m.

Co-Chairs: Reynold Hinger, Corridor Pipeline Ltd., Sherwood Park, Alberta
Mark Yeomans, TransCanada Pipelines Ltd., Calgary, Alberta

Rapporteur: Greg Hill, Corridor Pipeline Ltd., Sherwood Park, Alberta

Speakers: Bob Smyth, Petro-Line, Nisku, Alberta
Kyle Keith, Foothills Pipe Lines Ltd., Calgary, Alberta

Topic: Petro-Sleeves – Steel Compression-Type Pipeline Repair Sleeves

Notes (Bob Smyth Presentation):

- Bob Smyth passed around samples: a full-size cross-section of pipe and sleeve and a small-diameter version.
- The Petro-Sleeve is a steel repair sleeve designed for installation on an operating pipeline.
- The Petro-Sleeve works by changing the hoop-stress regime in the pipe wall from tension to compression.
- Compression is achieved by pre-heating (expanding) the sleeve just prior to installation, so that after installation, when it cools to operating temperature, its shrinkage is enough to drive the pipe wall into compression.
- The stress regime change effectively makes defects "disappear".
- How are Petro-Sleeves installed?
    - exterior wall of pipe in the area of defect is sand blasted
    - epoxy gel is applied to pipe
    - sleeve is heated to appropriate (calculated) temperature
    - sleeve halves are installed – first top then bottom
    - special jacks are used on large diameter sleeves
    - joining bars or "zippers" are welded to connect sleeve halves
    - sleeve is allowed to cool and shrink
- Additional points regarding installation:
    - for pipelines up to 24", heating is done by hand torches; a specially designed heater is used for larger lines
    - better results are achieved on flowing lines, as heat is transferred away more quickly once the sleeve is installed
    - longitudinal weld caps can either be ground flush or a groove can be ground into the sleeve
    - "zipper" fillet welds are very strong in tension (design factor is 0.92)
- Test results:
    - numerous tests have been done using strain gauges
    - notable were tests done on two samples (with 5 ft-lb Charpy values) at Canmet (Ottawa):

  - Petro-sleeve was applied to milled slot defect on test sample
  - multiple strain gauges were applied to pipe
  - internal pressure was applied to pipe 36,500 times at intervals of 40 seconds (equivalent to 1 shut-down per day for 100 years)
  - results revealed pipe wall hoop stress was never tensile, only compressive
  - strain disappeared 75mm from end of sleeve
  - edge stress was under 6000kPa, less than 15% of SMYS
- the test was repeated with a crack defect in the ERW seam:
  - sleeve was removed and pipe was sectioned
  - metallurgical tests revealed no growth in the crack defect
  - epoxy bond remained intact

Questions, Answers, and Discussion:

Question (Trevor MacFarlane, Dynamic Risk Assessment):

- What weld procedure is used?
- Is semi-automatic welding used?

Answer (Bob Smyth):

- 7018 rod with pre-heat.
- No, semi-automatic welding has not been used or found necessary.

Question (Trevor MacFarlane):

- Does the amount of compression achieved depend on the pressure in the pipeline when the sleeve is installed?

Answer (Bob Smyth):

- The sleeve thickness and temperature are selected based on the pressure and diameter to achieve the required compression.

Question (Shaun Dawe, Enbridge Pipelines):

- Have there been problems with ovality?

Answer (Bob Smyth):

- No.

Question (Shaun Dawe):

- Do the installation jacks force the pipe to round?

Answer (Bob Smyth):

- The internal pressure forces the pipe to round.

Question (Glenn Cameron, Greenpipe Industries):

- Can Petro-sleeves be used to repair buckles?

Answer (Bob Smyth):

- Petro-sleeves have been used for temporary repair of buckles prior to cut out and replacement.

Comment (Ron Charlesworth, EUB):

- A permanent repair of a severe buckle using a sleeve would likely affect the ability to carry out in-line inspection programs.

Comment (Bob Smyth):

- Petro-sleeves have been tested on dents. A test sample with a dent was pressurized – 1.5mm deflection of the dent was noted during pressurization. A sleeve was installed and pipe was re-pressurized – deflection was reduced to 0.05mm. Conclusion was that Petro-sleeves "freeze" dents in their configuration.

Question (?):

- Was a load-transferring agent required?

Answer (Bob Smyth):

- No, the epoxy acts as a load-transferring agent.

Question (David Katz, Williams Gas Pipelines West):

- Can Petro-sleeves be used on sag bends and over bends?

Answer (Bob Smyth):
- Yes. A recent example was on a 10in pipeline, where 3ft sleeves were cut to 1ft and fitted on a sag bend. 2ft and 3ft sleeves were used at the transition to straight pipe.

Question (Wayne Duncan, CSI Coatings):
- What pre-heat is used?

Answer (Bob Smyth):
- It depends on the variables, but typically 250°F for 16in-20in diameter and 550°F for 42in diameter.

Question (Ron Charlesworth):
- Does the pre-heat burn the epoxy?

Answer (Bob Smyth):
- No, the heat transfer to the flowing line creates a temperature gradient that prevents damage to the epoxy.

Notes (Kyle Keith Presentation):
- Background:
  - Foothills Pipeline is 1000km long, was constructed in 1980-1982
  - coating is polyken tape, so there are some areas of external corrosion
  - 13 excavations were done in 2000 as follow-up to an in-line inspection run
  - in 2000, 10 clock-springs and 10 Petro-sleeves were installed
  - the Petro-sleeves were fabricated from inventory pipe
- Qualification:
  - Petro-sleeves were approved by parent company (TCPL)
  - Foothill approved weld procedure
  - interpretation is that the sleeves can be used as permanent repairs for corrosion per CSA-Z662
  - awaiting CSA approval for dents / cracks
- Advantages:
  - better for longer defects than clock-springs
  - less risk of contact loss between sleeve and pipe
  - better resistance to SCC crack growth if SCC present
  - can be seen by in-line inspection tools
  - no welding to pipe required
- Disadvantages:
  - high initial cost
  - not good for significant bends
  - logistical (installation space) issues
  - can't see defect under sleeve using MFL tools
- Installation:
  - sleeves are installed with pipe at 80% of highest pressure seen in last several months
  - excavation is 600mm under pipe, 1500mm each side
  - long seam is ground flush rather than sleeve grooved

    - pipe / sleeve are blasted to NACE-2 finish
    - back-hoe is used to lift sleeve and jacks
    - welding inspector is used
    - MPI is done on fillet welds
    - epoxy is used to taper pipe to sleeve prior to re-coating
- Economics:
    - in BC, $/ft are approximately equal to clock-spring
    - for 36in pipeline, costs average $3000/ft
    - longer defects favor Petro-sleeves, since less sleeves need to be used – 3 Petro-sleeves are equivalent to 8 clock-springs
- Conclusions:
    - Petro-sleeves are approved for permanent corrosion repair
    - Petro-sleeves may be considered for linear defects and dents
    - economics are used to decide between Petro-sleeve and clock-spring for specific defects

Questions, Answers, and Comments:

Question (Reynold Hinger, Co-Chair):

- How do you determine that the annulus is completely filled with epoxy?

Answer (Bob Smyth):

- Epoxy is over-applied and squeezes out ends of sleeve.

Question (Patrick Porter, Clock Spring):

- CSA-Z662 allows the use of standard (non-compression) sleeves for permanent corrosion repair. Why use a Petro-sleeve?

Answer (Kyle Keith):

- Several reasons – we wanted to try it out, we can use our inventory pipe, and it gives us a better feeling about the integrity of the repair.

Question (Trevor MacFarlane):

- What wall thickness do you use?

Answer (Bob Smyth):

- We typically use about 1.5 times the pipe wall – I believe for Foothills we used 13.7mm on 8.2mm pipe.

Question (Glenn Cameron):

- Do ditch widths depend on diameter?

Answer (Bob Smyth):

- Yes, to an extent – the 36in and 42in sleeves require special lifting jigs and, therefore, a bit more clearance.

Question (Wayne Duncan):

- Have you looked at the compatibility of the topcoat and the epoxy used at the edge taper?

Answer (Kyle Keith):

- We haven't done any specific tests but the adhesion appears acceptable.

Question (Chris Pierce, Pierce Consulting):

- Have you had any weather related issue with the annulus epoxy?

Answer (Bob Smyth):

- We have done installation in –40°C and very hot weather as well. We make sure the epoxy is pre-warmed to ensure it doesn't freeze during mixing. Once it is applied it is kept warm by the pipeline and it will cure at 0°C and above.

Comment (David Katz):

- Regarding the previous ILI issue with clock-springs, we install steel banding with clock-springs so the ILI tool can identify them

Question (Scott Arndt, Husky Oil):

- Have you any experience on hot oil lines?

Answer (Bob Smyth):

- We worry about the epoxy we are using at temperatures higher than 65°C – it loses its strength. We are working on a solution now for well casings up to 300°C.

Comment (Barry Martins, Rainbow Pipe Line):

- We have been using steel epoxy-filled sleeves since the early 1990's. We were concerned about corrosion continuing under the epoxy but have pulled some sleeves off and have not found any problems with continuing corrosion.

Comment (Bob Smyth):

- Our standard QC procedure after installation is to check for electrical conductivity between the sleeve and pipe. We have always found that a bond exists and have not had to install jumpers.

Question (Frank Christenson, FM Christenson Mettalurgical Consulting):

- What is the status of CSA-Z662 approval?

Answer (Bob Smyth):

- Wording was presented at the March CSA-Z662 meeting. Changes are required in terminology – "bars" not "zippers", "steel compression sleeve" not "Petro-sleeve", etc. Petro-sleeves are OK for corrosion but not yet approved for dents, cracks, and arc burns. Letter ballot approval for these defects is hoped for by the end of the year.

Question (?):

- Can engineering assessments be used per CSA-Z662 to allow use on dents, cracks, and arc burns?

Answer:

- Maybe, but many companies won't go away from strict interpretation of the basic requirements of CSA-Z662.

Question (Frank Christenson):

- Have you sought approval for leak repair?

Answer (Bob Smyth):

- No, not yet, but we have done some initial testing on high-pressure leaks and the Petro-sleeves have performed well.

End of Session 1

Session 2:
Tuesday April 10th, 1:30 P.M., Max Bell Building, Room 251
Speaker:
John Hair, JD Hair & Associates, Tulsa, Oklahoma
Topic:
Horizontal Directionally Drilled (HDD) River Crossings

Notes:

- Summary of current capabilities of HDD
  - drills of more than 6000ft have been achieved
  - largest diameter pipeline ever installed using HDD is 48in
  - drills have been done in rock, but are usually done in fine-grain alluvial material
  - an 3000 ft HDD crossing for 42in pipe is not unreasonable
  - we usually look at the history to determine if a proposed crossing is reasonable
  - some say a 10,000ft crossing will be done in the future
  - the only thing that prevents a successful HDD crossing is coarse-grain material (having boulders / cobbles) – crossings where these materials are present are better done a different way
- General design considerations
  - 1st step is to define the obstacle – there are a number of ways HDD crossings can be done, i.e. bank to bank, channel only, etc. – what exactly are you trying to achieve with the HDD crossing and what are you trying to avoid?
  - 2nd step is to carry-out an accurate, but not necessarily detailed surface survey, with control point – a complete profile of the river bottom is not required, but determination of the deepest point is
  - 3rd step to do a sub-surface survey, primarily using bore holes, occasionally supplemented by ground-penetrating RADAR.
- Cross sectional profile (Overhead #1 – typical drill path profile):
  - typically, HDD contractors should not design the crossing profile
  - for bidding consistency, potential contractors should be given a profile at bid stage, with profile tolerance and maximum / minimum radii of curvature
  - key points on radii of curvature:
    - the longer the better
    - circular curves are laid out
    - rule of thumb for minimum radii – 100 times (in feet) the nominal diameter (in inches), i.e. 3000ft for 30in diameter pipe
    - when HDD is done, the actual radii might be tighter
    - JD Hair & Assoc. looks at worst case for stress analysis
- Pulling loads (Overheads #2 & #3 – pulling load calculations)
  - JD Hair & Assoc. received research contract from PRCI to determine pulling load calculation methodology
  - divided drill path into straight and curved sections to determine soil friction loads
  - use 0.3 as coefficient of sliding friction
  - incorporated fluidic (mud) drag
  - use 0.025psi of surface area for fluidic drag

- Drill path design example (Overhead #4 – target and worst case drill profiles)
  - Target and worst case drill profiles are developed and stress analysis is done on the worst case
- Drill path design example (Overheads #5 & #6 – typical stress analysis results summary)
  - Part of PRCI research contract was to determine stress calculation and acceptance criteria methodology
  - API specification for combined loading on offshore platform jacket structures turned out to be most applicable to the HDD case
  - pipe is divided into segments
  - combined tensile, bending, and buckling stresses in each segment are used to determine acceptability of drill path
- Coating damage assessment (Overheads #7 & #8 – bearing load on coating)
  - JD Hair & Assoc. received another research contract from PRCI to determine bearing loads on coatings and assess potential coating damage
  - again straight and curved cases were assessed to determine typical bearing loads
- Coating damage assessment (Overhead #9 – test apparatus)
  - 8in coated pipe was placed in a tank of mud and rotated while the ends of three rock cores were forced against it
  - forces on rock cores were determined to achieve bearing loads calculated in the first part of the research
  - coating thickness was recorded at intervals along the pipe under the rock cores at 0hrs, 6hrs, and 12hrs
  - point load test (sharpened core) was also carried out
- Coating damage assessment (Overheads #10 & #11 – test results)
  - coating losses were only up to 15mils (worst sample) after 12 hours
  - point load test showed rapid initial coating loss but rock point seemed to dull quickly and continued loss did not occur
  - conclusion was that previous practice of putting 80-100mils of wear coating on HDD pipe was over-kill – 30-40mils was determined to be completely adequate
- Environmental issues (Overhead #12 – HDD drilling fluid flow schematic)
  - drilling mud return flow will follow path of least resistance, which is usually along the outside of the pipe but may be into weak or fractured areas of the soil
  - common term is "frac-out", but better term is "inadvertent mud return"

Slide Show:

- Photo #1: 30in diameter pipe for high volume, low pressure pipeline, buckled during HDD pull under the Houston Ship channel – d/t ratio of 100 was not adequate to prevent collapse from external pressure
- Photo #2: 16in diameter pipe, buckled during HDD pull
- Photo #3: pulling head on pipe in Photo #2 – head hit rock and buckle propagated to pipe
- Photo #4: 16in pipe being pulled under Mississippi River – lots of mud at hole entrance (normal)
- Photo #5: close-up of hole in Photo #4, now dry – mud disappeared through subsurface pathways
- Photo #6: close-up of road surface with mud oozing from HDD drill path 60ft below

- Photo #7: road in Photo #6 flooded with mud
- Photo #8: mud seeping from roadside (Niagara Peninsula)
- Photo #9: mud oozing up in grassy area
- Photo #10: photo of grassy mud-seep area, several weeks later – no damage to grass
- Photo #11: wash-out of road caused by mud-seep into sub-grade

Questions and Answers:

Question (John Craig, Pacific Northern Gas):

- How many bore hole locations are required?

Answer (John Hair):

- Usually one per 1000ft; 500ft spacing is considered close. The biggest mistake made is usually depth not spacing – bores should extend a minimum of 30ft below the proposed drill path.

Question (Ron Charlesworth, EUB):

- Does polyethelyne make a good protective coating?

Answer (John Hair):

- Polyethelyne may be good, but the weak point is probably the girth-weld coating. Some good results have been achieved with armored sleeves.

Question (John Craig):

- Do you have a rating system for coatings?

Answer (John Hair):

- 11 coatings were tested and each given a wear index, however, a better wearing coating may not be better if it costs more – a cheaper coating can be put on thicker to achieve the same result.

Question (?):

- Are liners (casings) ever used to mitigate problems with inadvertent mud return?

Answer (John Hair):

- Not usually – the casing has to be installed using the same method as the pipe, with the same inherent problems, so there is no benefit. In general, as well, the industry tends to avoid casings where possible.

Question (John Craig):

- Can casings be used in localized areas?

Answer (John Hair)

- Yes, like near the drill rig, but they tend to cause other problem, causing the reaming / pulling tools to get hung up, for example.

Question (Daryll Wendland, Alliance Pipeline):

- Are there any techniques to prevent inadvertent mud return?

Answer (John Hair):

- The best technique is to size the hole properly so that the path of least resistance is along the drill path, as intended. In our experience, other techniques attempted to prevent inadvertent return have not worked well. The best option is to proceed quickly with the drill, ream, or pull – as the work proceeds the problem usually disappears. It is important to note that the mud itself is not an environmental hazard – if the public is protected from washouts or unstable areas, then an inadvertent return is not usually a big problem.

Question (Jeff Sutherland, BJ Pipeline Inspection Services):

- How is the drill path verified?

Answer (John Hair):

- The best way is to monitor the pilot hole, with the driller, and look at the exit point. Some have pulled a "geo"-pig through (both ways, distributing the error), for independent verification, but this is rare.

Question (Mark Ottem, Trans Mountain Pipe Line):

- What is the accuracy of navigation?

Answer (John Hair)

- We can usually give an "as-built opinion" within +/- 1m in any direction.

Question (Dave Hektner, BJ Pipeline Inspection Services):

- How do you ensure radii are not to sharp? Is re-reaming an option?

Answer (John Hair):

- Best method is to use heavier drill / reaming pipe to start. Re-reaming has little benefit; the second ream is deflected by the same discontinuities as the first.

End of Session 2

Session 3:
Tuesday April 10th, 3:30 P.M., Max Bell Building, Room 251
Speaker:
Barry Nichols, HCI Canada Inc., Red Deer, Alberta
Topic:
Enhancement of Pipeline Pigging Programs

Notes:

- Why enhance a pigging program?
    - improve flow efficiency by removing deposits from walls
    - improve inspection results – deposits in pits can cause problems
    - improve film application on inhibitor runs
    - remove more solids per run
    - reduce differential pressure on pigging runs
    - reduce chances of pigs becoming stuck
- Typical cleaning pig characteristics:
    - mechanical force at pipe wall
    - push material through pipeline
    - bypass holes to create turbulence
- Cleaning pig features:
    - brushes
        - not good for pits
        - effectiveness is determined by stiffness, size, shape, and orientation
    - cups / discs
        - effectiveness determined by thickness, hardness, shape, and velocity
- Cleaning pigs are not designed for:
    - suspending solids in a long fluid column
    - penetrating solids
    - getting deep into pits
    - coating solids to keep them from sticking together
    - bringing solids out in a slurry
- Chemicals are necessary and used to assist cleaning pigs with these tasks.
- Case History #1:
    - pipeline:
        - 218km of 20in diameter pipeline (Toronto to Sarnia)
        - originally in crude service
        - cleaned and put into products service
    - problem:
        - line was being cleaned on-stream
        - refined products were being contaminated with fine solids (iron-based)
        - time had to be allowed in tanks to allow solids to settle
        - 17 pig runs were made with 4 to 7 aggressive cleaning pigs per run, at turbulent velocities
        - at the ¼ point along the line, refined products were still going off-spec

- solution:
    - chemicals were run with cleaning pigs, one chemical to penetrate solids, and one to suspend solids
    - two runs were carried out with 4 pigs in each run and chemicals selectively placed between pigs
- results:
    - after 1st cleaning run, the products were clean up to the ¾ point along the line and the quality at the end point was significantly improved
    - after the 2nd cleaning run, the exiting products were essentially as clean as the entering products
- Case History #2
    - black powder was packed into pits in pipe wall by previous cleaning runs
    - after chemicals were added to cleaning runs and dry powder was removed, some pits thought to be 20% deep were actually 60% deep
    - demonstrates importance of chemical cleaning before ILI runs
- Case History #3
    - offshore pipeline almost completely plugged with wax
    - chemical was added to dissolve wax and forced through with pressure until line was clean

Photos:

Photo #1: Case History #1 – pigs used.
Photo #2: Case History #1 – solids in pipeline.
Photo #3: Case History #1 – samples taken as pig train passed (front to back). Last sample is crystal clear.
Photo #4: Picture of typical pipe wall coupon with deposits.
Photo #5: Case History #2 - dry powder in another pipeline.
Photo #6: Case History #3 - offshore pipeline almost completely plugged with wax.

Questions, Answers, and Discussions:

Question (Reynold Hinger, Co-Chair):

- Do you ever use gel pigs in these situations?

Answer (Barry Nichols):

- No – gel pigs are designed for lines in which regular pigs can't be run. They are a second choice for piggable lines because they leave too many residues.

Question (Ron Charlesworth, EUB):

- How do you adjust for speed?

Answer (Barry Nichols):

- We adjust the slug lengths for the speed and the type of chemical so that deposits are exposed to the chemical for the appropriate time. Sometimes you don't want to clean everything on the 1st past if you can't handle all of the sludge at one time.

Question (Ron Charlesworth):

- What is a typical slug length?

Answer (Barry Nichols):

- It is highly variable, depending on speed, deposits, and chemical types, but typically several hundred feet for a flow rate of 500m3/hr.

Question (Ron Charlesworth):

- Can you comment on freezing? We had an experience with this.

Answer (Barry Nichols):

- We have to be very careful to mix the chemicals properly so that the slugs don't freeze.

Question (?):

- Is there a guideline for exposure time for effective cleaning (i.e. duration per mil of deposit)?

Answer (Barry Nichols):

- Again, this depends on the type of deposit and the chemical being used.

Question (Anton Walker / Jerry Wilkinson):

- How do you know before hand what deposits are in the line?

Answer (Barry Nichols):

- You try to get a sample if you can or you design for a wide range of factors. You don't want to risk improper cleaning before an ILI run, for example, and have to do the run again or unknowingly get bad results.

Question (?):

- Are the chemicals hazardous?

Answer (Barry Nichols):

- No – we use environmentally friendly, non-hazardous chemicals.

Question (Dan Powell, Corrpro Canada):

- Can you recycle the cleaning chemicals?

Answer (Barry Nichols):

- No, like all surfactants (dish detergent, etc.) they have a finite life.

Question (Trent Van Egmond, TransCanada Pipelines):

- Have you heard of, or used, pin wheel pigs, and are they effective for cleaning pits?

Answer (Barry Nichols):

- Yes, but they have limited effectiveness for cleaning pits since they are travelling forward and the pin wheels bend back. Again, chemicals are a necessity for cleaning pits.

Question (?):

- What about compressor oil residue?

Answer (Barry Nichols):

- Again, a pig alone will smear the residue along the pipe – proper chemicals are required for effective cleaning.

Question (?):

- Are internal coatings affected by the chemicals?

Answer (Barry Nichols):

- No – the internal coatings are very strongly bonded to the pipe wall and cannot be removed by cleaning chemicals.

Question (Dan Powell):

- What do you do about multi-diameter lines?

Answer (Barry Nichols):

- You have to design the pigs for one diameter or the other, usually the smallest, or use multiple diameter cups. The problem is that in the small line the large cups may wear quickly and then be ineffective in the big line, depending on the pigging order. Again, chemicals are key to get the most effective cleaning.

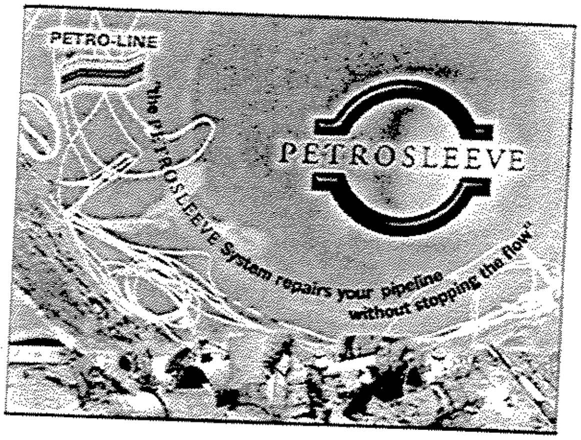
Question (Jill Hopkins, Conoco):

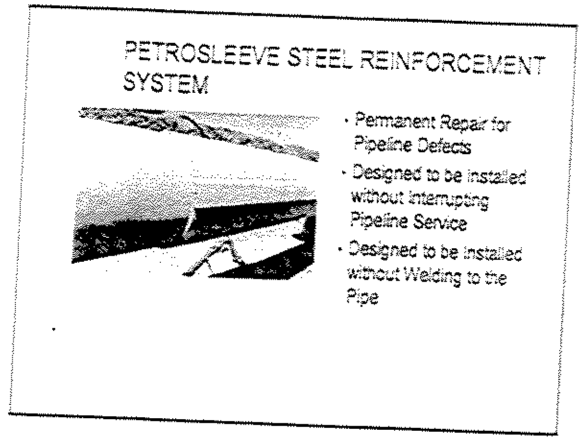
- Have you heard of, or used, magnetic cleaning pigs, and are they effective?

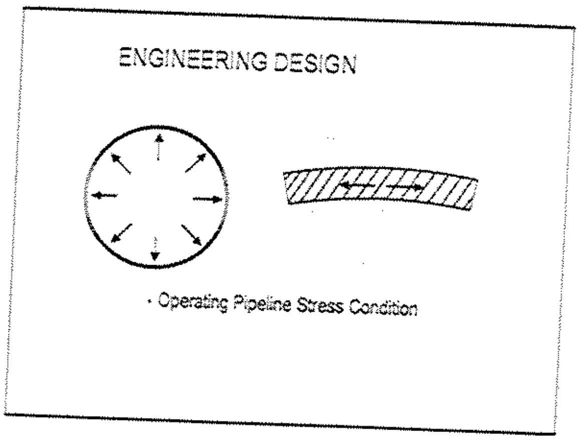
Answer (Barry Nichols):

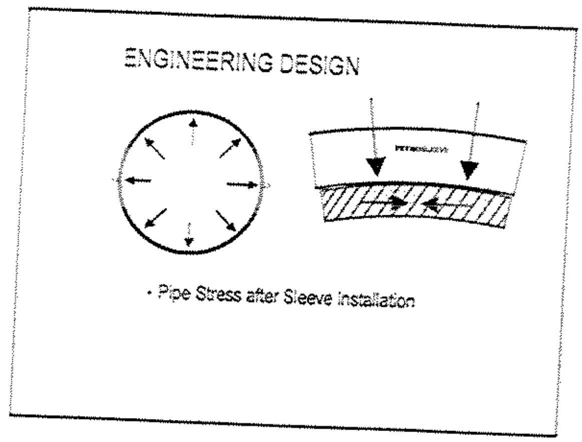
- They can be effective for iron-based deposits but they have limited capacity. They are very effective for larger magnetic items like welding rods, etc. They can also be effective in combination with other cleaning pigs and chemicals.

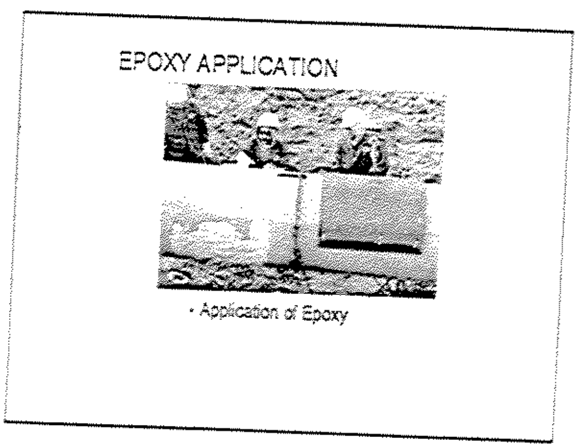
End of Session 3

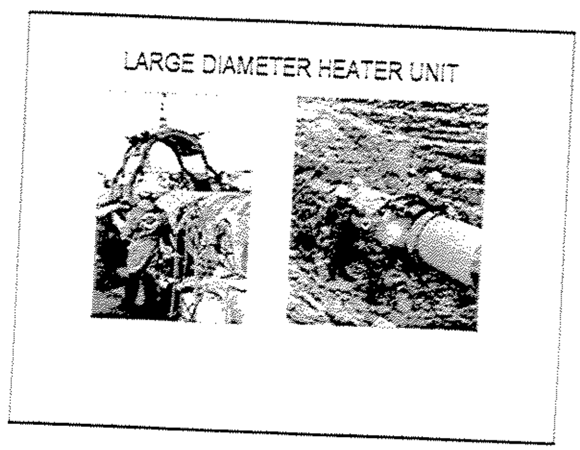

PETRO-LINE
PETROSLEEVE
"The PETROSLEEVE System repairs your pipeline without stopping the flow"


PETROSLEEVE STEEL REINFORCEMENT SYSTEM
· Permanent Repair for Pipeline Defects
· Designed to be installed without interrupting Pipeline Service
· Designed to be installed without Welding to the Pipe

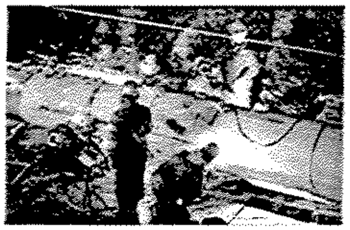

ENGINEERING DESIGN
· Operating Pipeline Stress Condition


ENGINEERING DESIGN
PETROSLEEVE
· Pipe Stress after Sleeve Installation

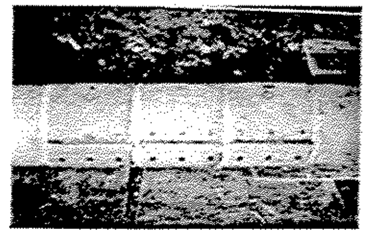

EPOXY APPLICATION
· Application of Epoxy


LARGE DIAMETER HEATER UNIT

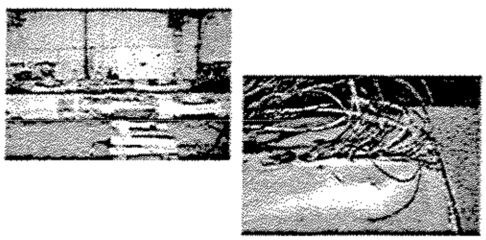
COMPLETION OF WELDING



MULTIPLE SLEEVE INSTALLATIONS



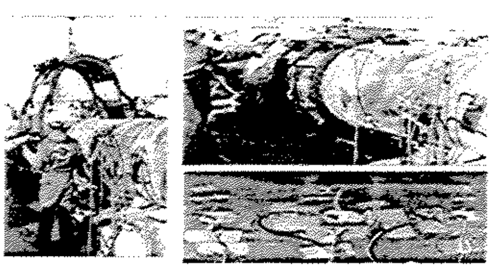
STRAIN GAUGE TESTING



DENT TESTING

- Dent Created by Backhoe

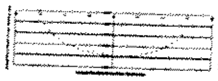
LARGE DIAMETER TESTING



STUDY OF SLEEVE EDGE EFFECTS AND ABILITY TO PREVENT FAILURE OF SERIOUS PIPE DEFECTS

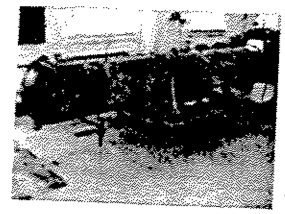
- Study Edge Stress Effects Created When a PetroSleeve is Installed
- Determine the Sleeve's Ability to Prevent Failure of Serious Pipe Defects
- Severe Cyclic Test Performed to Measure Effect of Sleeve on Pipe with Low Charpy Impact Values
- Tests Augmented with Strain Gauge Application
- 36,500 pressure cycles
- 0.09 R value for each cycle (689 kPa to 8048 kPa)

DEFECT MANUFACTURE



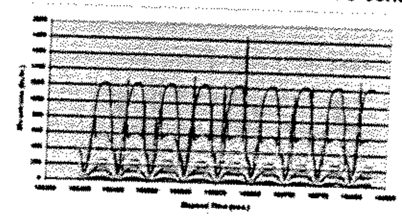
- Slot 300 mm (12") Long
- Parabolic Depth Profile
- 70% Maximum Depth in Centre of Defect
- Electrically Discharged Machined (EDM) into ERW Longseam
- Finite Element Analysis (FEA) Predicted Rupture Pressure of 1400 kPa

CANMET PRESSURE CYCLING



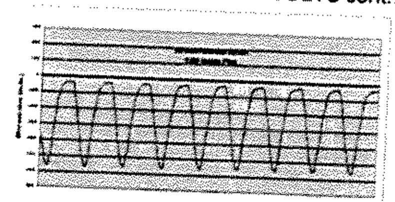
- 16 Strain Gauge Channels
- Readings Recorded 26 times per Pressure Cycle
- 24 Hold Test at 8048 kPa
- Cycled from 689 kPa to 8048 kPa
- One Cycle Every 40 seconds
- Total of 36,500 Cycles
- All 16 Channels Recorded During Sleeve Removal

PRESSURE CYCLING RESULTS cont....



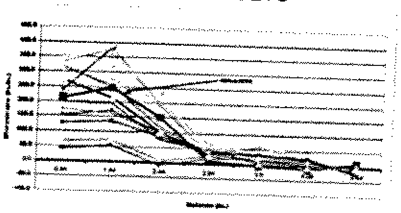
- Strains Measured During Cycle Test

PRESSURE CYCLING RESULTS cont....



- Strains Inside Pipe Under Sleeve at 6:00 Position

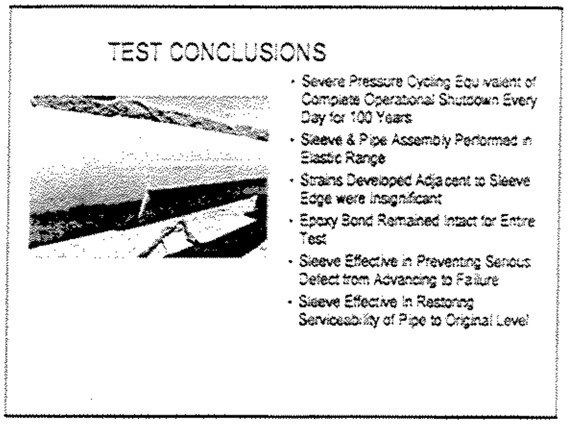
PREVIOUS TEST RESULTS

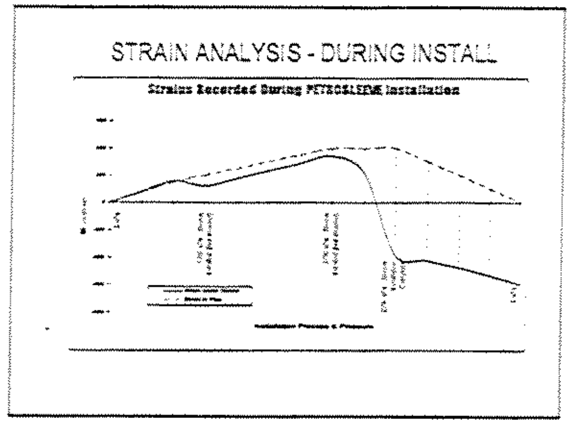


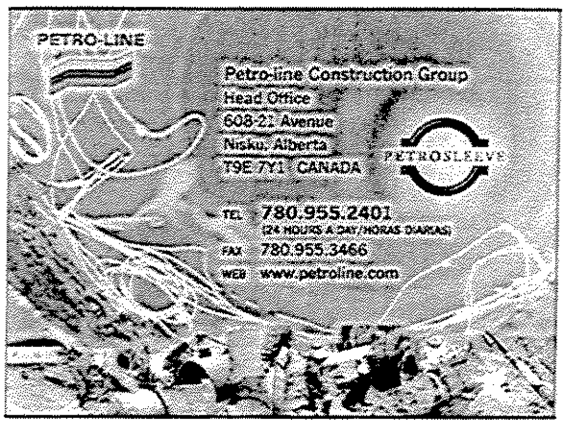
- Previous Test Results – Edge Effect Strains

PRESSURE CYCLING RESULTS

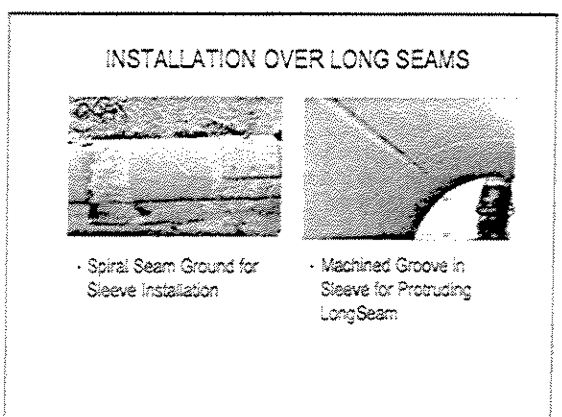
- No Failure Observed for the 36,500 cycles
- No Failure in:
  - Pipe Adjacent to Sleeve
  - Sleeve Material
  - Sleeve Fillet Weld
  - EDM Defect
- Final State of Vessel Same as Initial
- MPI of Sleeve and Adjacent Pipe Revealed NO Cracking


TEST CONCLUSIONS
• Severe Pressure Cycling Equivalent of Complete Operational Shutdown Every Day for 100 Years
• Sleeve & Pipe Assembly Performed in Elastic Range
• Strains Developed Adjacent to Sleeve Edge were Insignificant
• Epoxy Bond Remained Intact for Entire Test
• Sleeve Effective in Preventing Serious Defect from Advancing to Failure
• Sleeve Effective in Restoring Serviceability of Pipe to Original Level


STRAIN ANALYSIS - DURING INSTALL
Strains Recorded During PETROSLEEVE Installation


PETRO-LINE
Petro-line Construction Group
Head Office
608-22 Avenue
Nisku, Alberta
T9E 7Y1 CANADA
PETROSLEEVE
TEL 780.955.2401
(24 HOURS A DAY/HORAS DIARIAS)
FAX 780.955.3466
WEB www.petroline.com


INSTALLATION OVER GIRTH WELDS
• Grooved Sleeve for Installation over Girth Weld


INSTALLATION OVER LONG SEAMS
• Spiral Seam Ground for Sleeve Installation
• Machined Groove in Sleeve for Protruding LongSeam

PETROSLEEVE INSTALLATION 2000

FOOTHILLS PIPE LINES LTD

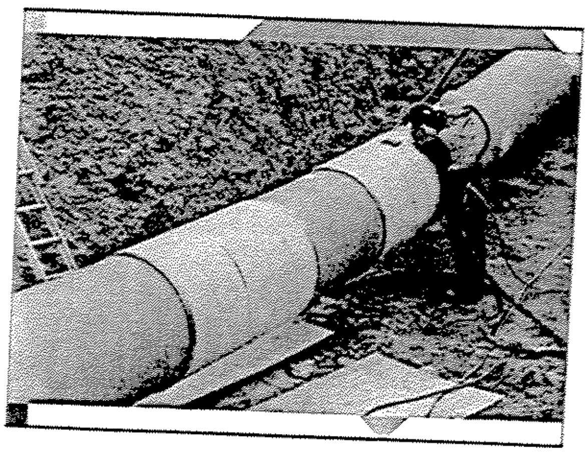
Kyle Keith

INTRODUCTION

- Background
- Qualifications
- Operational Issues
- Installati on
- Costs

BACKGROUND

- FOOTHILLS PIPE LINES LTD - Prebuilt
  - 1980-1982 Construction
  - Double Wrap Polykin Tape
  - 1000 km of NPS 36&42 in AB,BC,SK
- In-line Inspection (ILI) Program
  - 2000 PII & BJ inspected 180+km
  - 13 Excavations
- History of repairs
  - Pre 2000, 1 clockspring
  - 2000: 10 Clocksprings and 10 PETROSLEEVES
- PETROSLEEVES fabricated from inventory pipe



QUALIFICATION

- Approved by TCPL
- Foothills approved Petro-Line weld procedures
- Class A repair sleeve as defined in CSA Z662 sec 10.8.

COMPAIRISON TO FIBREGLASS SLEEVES

- ADVANTAGES
  - Covers longer defects
  - Less risk of loosing contact with pipe
  - Resistance to SCC and fatigue defects
  - Can be detected on future ILI [MFL] runs

COMPAIRISON TO FIBREGLASS SLEEVES

- DISADVANTAGES
  - Relatively high mobilization and unit costs
  - Can not be installed on significant bends
  - Logistical issues with equipment and personnel
  - Requires wider/deeper ditch
  - Defect can not be sized on future ILI [MFL] runs

OPERATIONAL ISSUES

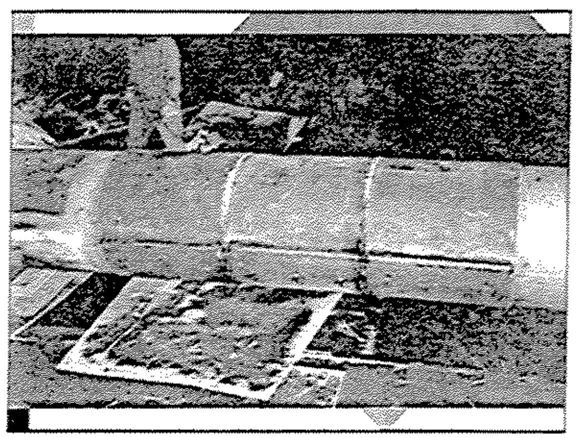
- Pressure reduction to 80% recent MOP (Foothills' Policy)
- Inspection - Weld inspector, familiar with sleeve installation
- NDE - MPI performed on fillet welds and pipe longseam
- Must grind LS weld or cut groove in sleeve
- Ditch must have direct access for picker (backhoe) and two welding rigs

INSTALLATION

- Grit blasted to a NACE 2 finish (green diamond)
- Require 600 mm clearance under the pipe and 1500 mm on each side
- Recoating
  - Blast and coated over the sleeve as with rest of piping
  - Epoxy was used to taper transition between sleeve ends and the line pipe
  - Modified coating spec from split sleeve coating specification
- The backhoe was used as a lifting device
- Handover documents - Petro-Line

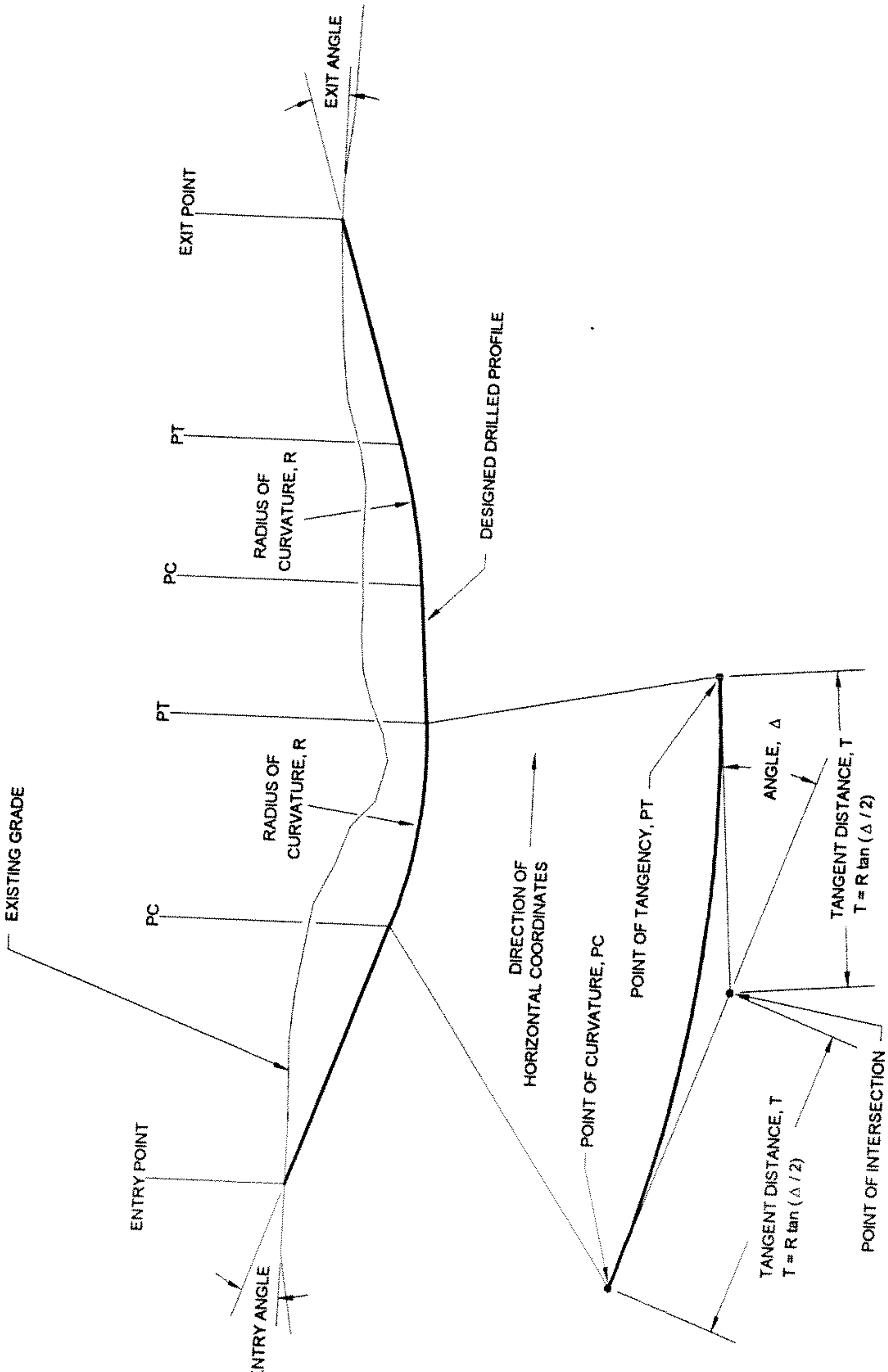
ECONOMICS

- Costs to install a Fiberglass sleeve approximately equal ($/ft) for longer defects
  - The longer the defect(s) and the more defects to be repaired the more favorable the economics are for the Petrosleeves
  - The shorter and more isolated the defect, the economics favor the fiberglass sleeves
- Approximately $3000/ft total sleeve repair costs for NPS 36 repair in BC

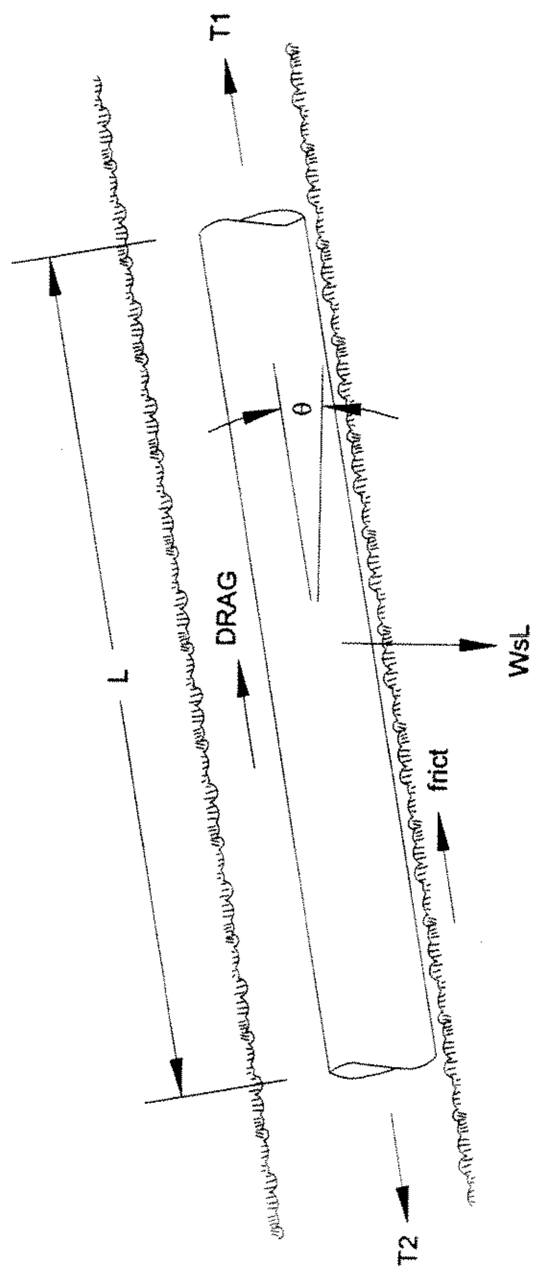


CONCLUSIONS

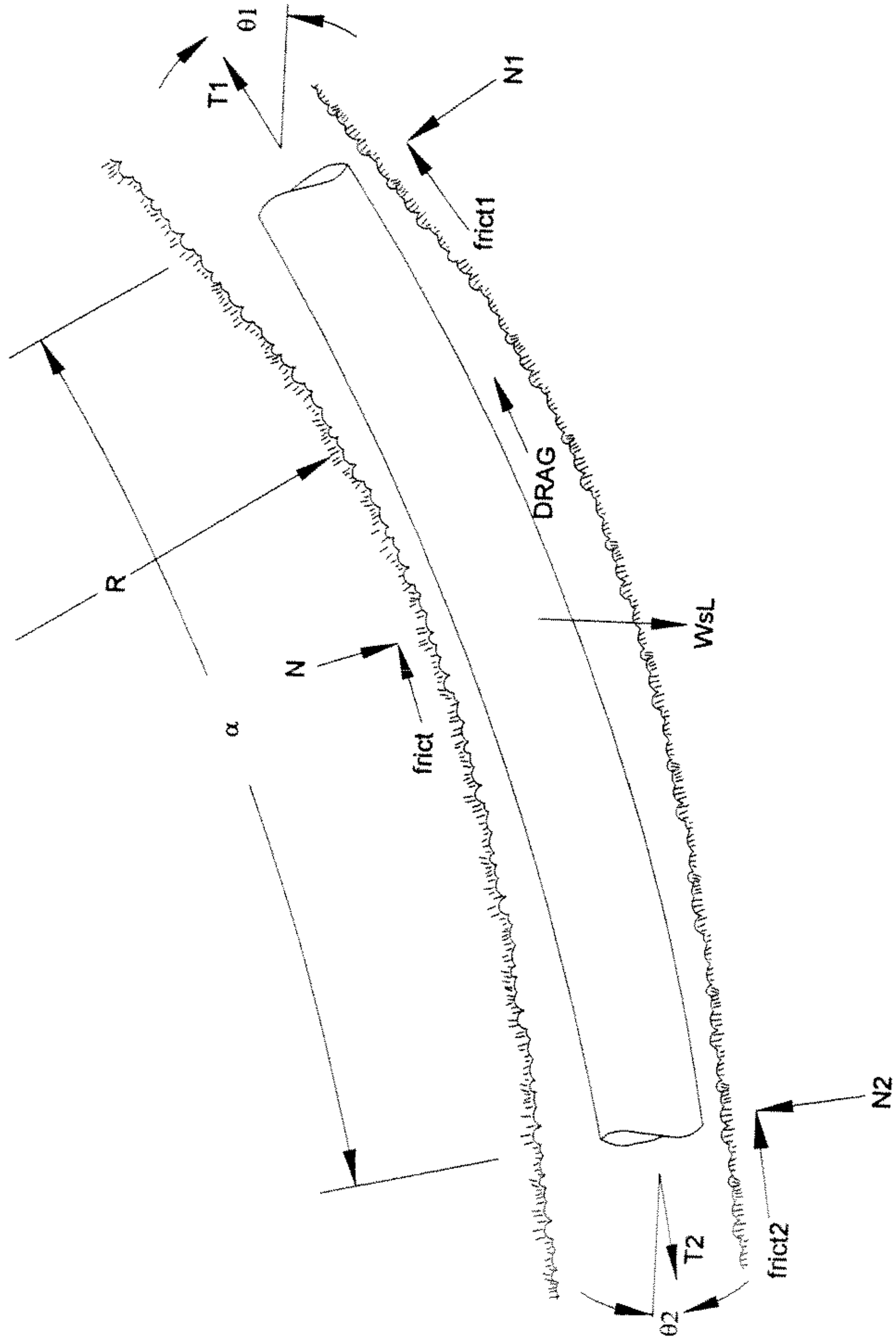
- PetroSleeves are an approved method for the permanent repair of corrosion defects on Foothills' system.
- Foothills will consider using petrosleeves on other types of defects (i.e. dents, cracks gouges) on a case by case basis.
- Type of repair method used is based on an engineering decision that considers defect specifics and total costs of repair vs. other acceptable repair methods.

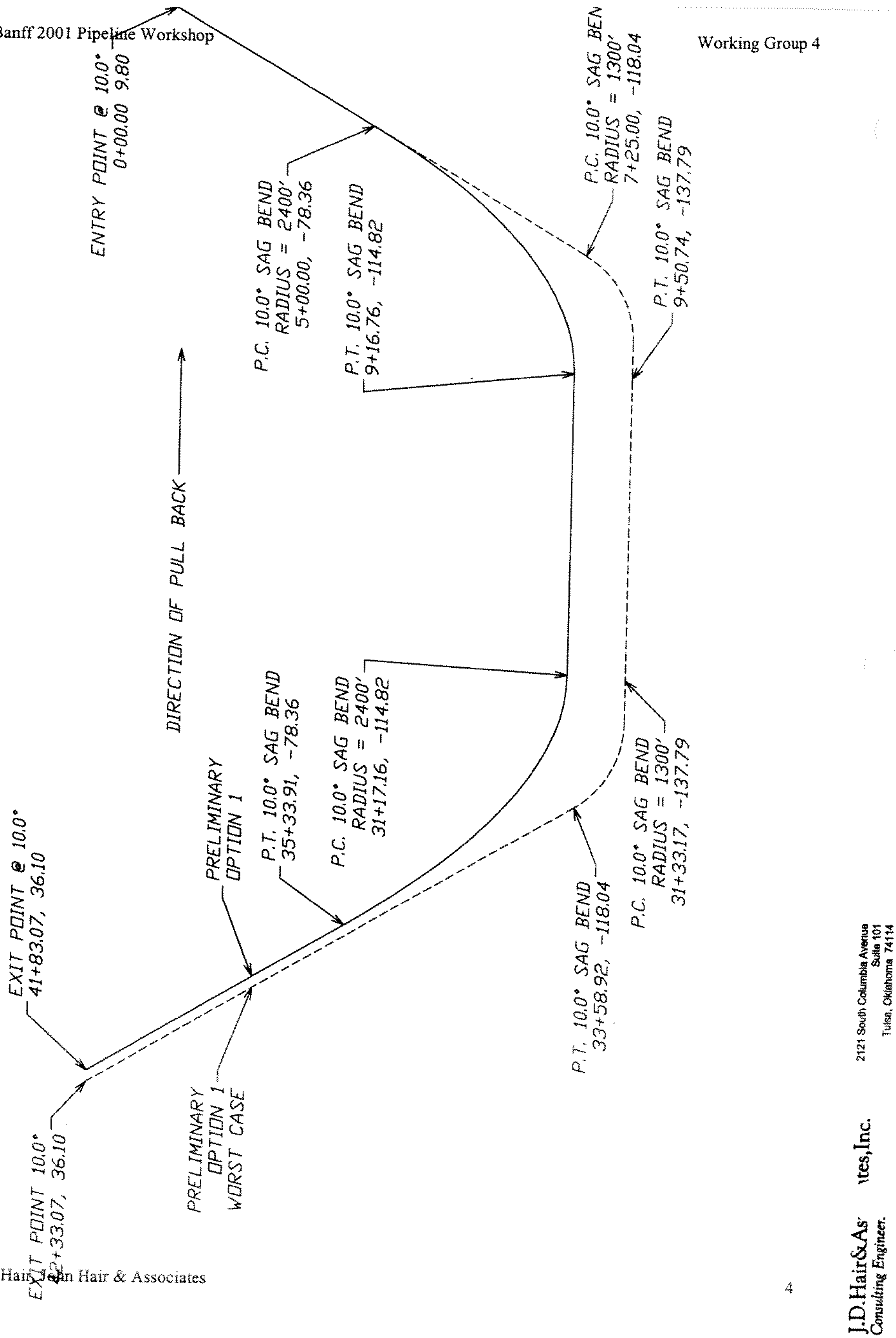

EXIT ANGLE
EXIT POINT
DESIGNED DRILLED PROFILE
PT
RADIUS OF CURVATURE, R
PC
PT
RADIUS OF CURVATURE, R
PC
EXISTING GRADE
ENTRY POINT
ENTRY ANGLE
DIRECTION OF HORIZONTAL COORDINATES
POINT OF CURVATURE, PC
POINT OF TANGENCY, PT
ANGLE, Δ
TANGENT DISTANCE, T
T = R tan (Δ / 2)
POINT OF INTERSECTION
TANGENT DISTANCE, T
T = R tan (Δ / 2)

Straight Section Model



Curved Section Model




ENTRY POINT @ 10.0°
0+00.00 9.80
P.C. 10.0° SAG BEND
RADIUS = 2400'
5+00.00, -78.36
P.T. 10.0° SAG BEND
9+16.76, -114.82
P.C. 10.0° SAG BEN
RADIUS = 1300'
7+25.00, -118.04
P.T. 10.0° SAG BEND
9+50.74, -137.79
DIRECTION OF PULL BACK
P.C. 10.0° SAG BEND
RADIUS = 2400'
31+17.16, -114.82
P.T. 10.0° SAG BEND
35+33.91, -78.36
PRELIMINARY
OPTION 1
EXIT POINT @ 10.0°
41+83.07, 36.10
P.C. 10.0° SAG BEND
RADIUS = 1300'
31+33.17, -137.79
P.T. 10.0° SAG BEND
33+58.92, -118.04
EXIT POINT 10.0°
2+33.07, 36.10
PRELIMINARY
OPTION 1
WORST CASE
J.D.Hair&As tes,Inc.
Consulting Engineer.
2121 South Columbia Avenue
Suite 101
Tulsa, Oklahoma 74114

Date:

File: Option 1 Pulling ...s Sheet: Summary

PULLING LOAD CALCULATION AND INSTALLATION PIPE STRESS ANALYSIS

Project:

Directory:

Description: Option 1

Prepared: MST Date: 9/18/00

Checked: JDH Date: 9/20/00

General Data

Pipe Diameter =	24.000 inches
Wall Thickness =	0.500 inches
SMYS =	65,000 psi
Young's Modulus =	2.9E+07 psi
Moment of Inertia =	2548.20 $inches^4$
Pipe Face Surface Area =	36.91 $inches^2$
Diameter/wall thickness ratio =	48
Poisson's ratio =	0.3
Mud Density =	12.0 ppg
=	89.8 $pounds/foot^3$
Ballast Density =	62.4 $pounds/foot^3$
Coefficient of Soil Friction =	0.30
Fluid Drag Coefficient =	0.025 psi
Pipe Weight in Air=	125.49 pounds/foot
Pipe Interior Volume=	2.89 $feet^3/foot$
Pipe Exterior Volume=	3.14 $feet^3/foot$
Ballast Weight =	180.04 pounds/foot
Displaced Mud Weight =	281.99 pounds/foot

Results Summary

	Segment 1	Segment 2	Segment 3	Segment 4	Segment 5
Is this segment submerged in mud?	yes	yes	yes	yes	yes
Is this segment ballasted?	no	no	no	no	no
Cumulative Pulling Load at End Point =	63,301	109,186	262,266	307,298	328,460
True Length to End Point from Beginning =	659	1,078	3,278	3,697	4,205
Tensile Stress Check:	Passed	Passed	Passed	Passed	Passed
Bending Stress Check:	NA	Passed	NA	Passed	Passed
Hoop Stress Check:	Passed	Passed	Passed	Passed	NA
Combined Tensile and Bending Stress Unity Check:	NA	Passed	NA	Passed	NA
Combined Tensile, Bending and External Hoop Stress Unity Check:	Passed	Passed	Passed	Passed	Passed

STEEL PIPE STRESS CHECKS USING AGA DESIGN GUIDE CRITERIA		
Allowable Tensile Stress Calculation, F_t		
Tensile Stress Limit, 90% of SMYS, F_t =	58,500 psi	
Allowable Bending Stress Calculation, F_b		
For D/t <= 1,500,000/SMYS, F_b =	48,750 psi	Not Applicable
For D/t > 1,500,000/SMYS and <= 3,000,000/SMYS, F_b =	42,432 psi	Not Applicable
For D/t > 3,000,000/SMYS and <= 300, F_b =	42,744 psi	**Applicable**
Allowable Bending Stress, F_b =	42,744 psi	
Critical Hoop Buckling Stress Calculation, F_{hc}		
Elastic Hoop Buckling Stress, F_{he} =	11,076 psi	
For F_{he} <= 0.55*SMYS, Critical Hoop Buckling Stress, F_{hc} =	11,076 psi	**Applicable**
For F_{he} > 0.55*SMYS and <= 1.6*SMYS, F_{hc} =	31,244 psi	Not Applicable
For F_{he} > 1.6*SMYS and <= 6.2*SMYS, F_{hc} =	12,133 psi	Not Applicable
For F_{he} > 6.2*SMYS, F_{hc} =	65,000 psi	Not Applicable
Critical Hoop Buckling Stress, F_{hc} =	11,076 psi	
Allowable Hoop Buckling Stress, $F_{hc}/1.5$ =	7,384 psi	
Segment 1, Straight Segment		
Tensile Stress, f_t =	1,715 psi	Passed
External Hoop Stress, f_h =	1,712 psi	Passed
Combined Tensile and External Hoop Stress Unity Check =	0.06	Passed
Segment 2, Deflected Segment		
Tensile Stress, f_t =	2,958 psi	Passed
Bending Stress, f_b =	12,083 psi	Passed
External Hoop Stress, f_h =	2,258 psi	Passed
Combined Tensile and Bending Stress Unity Check =	0.33	Passed
Combined Tensile, Bending and External Hoop Stress Unity Check =	0.21	Passed
Segment 3, Straight Segment		
Tensile Stress, f_t =	7,105 psi	Passed
External Hoop Stress, f_h =	2,258 psi	Passed
Combined Tensile and External Hoop Stress Unity Check =	0.13	Passed
Segment 4, Deflected Segment		
Tensile Stress, f_t =	8,325 psi	Passed
Bending Stress, f_b =	12,083 psi	Passed
External Hoop Stress, f_h =	1,712 psi	Passed
Combined Tensile and Bending Stress Unity Check =	0.42	Passed
Combined Tensile, Bending and External Hoop Stress Unity Check =	0.25	Passed
Segment 5, Straight Segment		
Tensile Stress, f_t =	8,898 psi	Passed
External Hoop Stress, f_h =	393 psi	Passed
Combined Tensile and External Hoop Stress Unity Check =	0.04	Passed

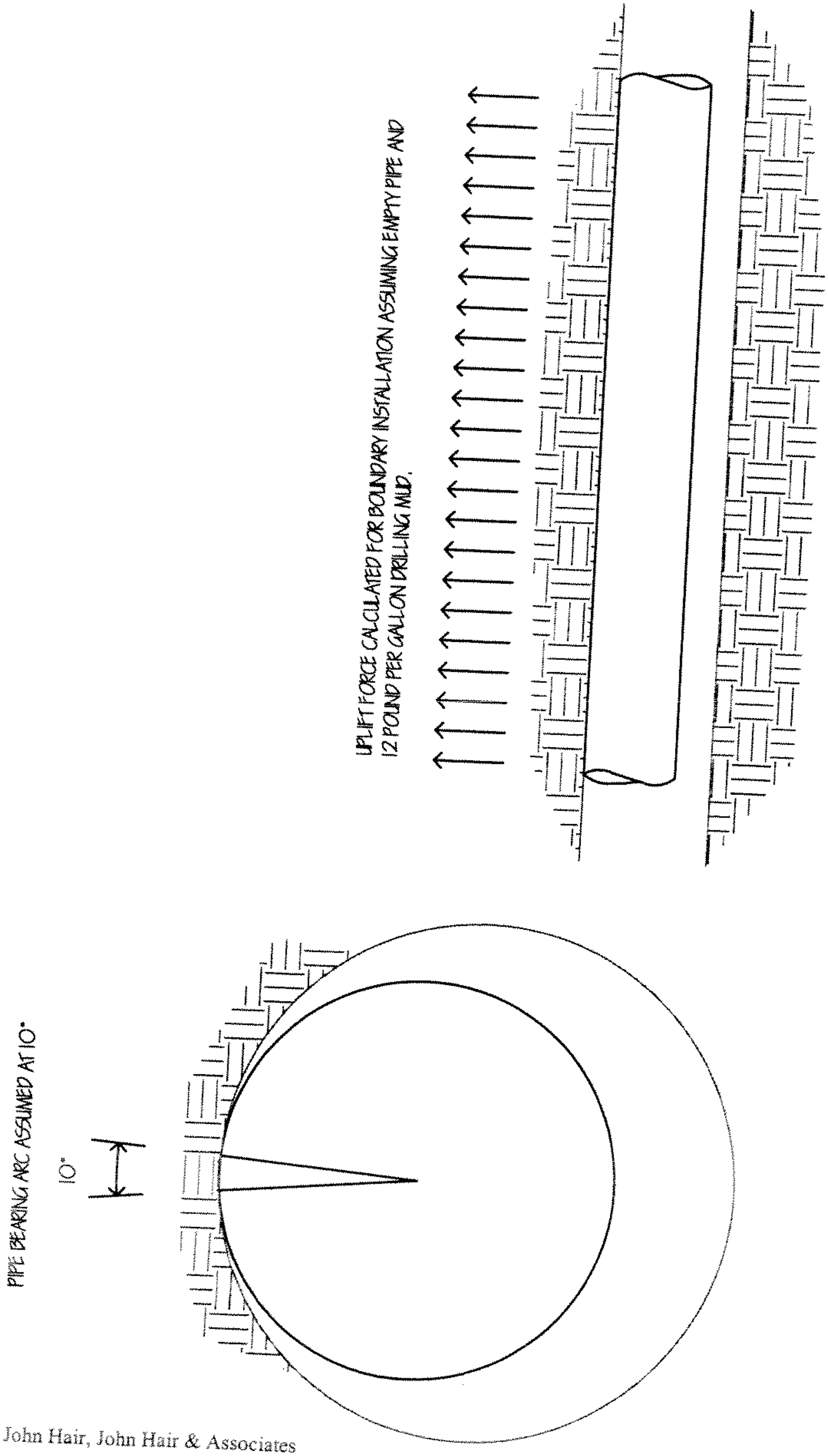


FIGURE 1. BEARING FORCE RESULTING FROM WEIGHT

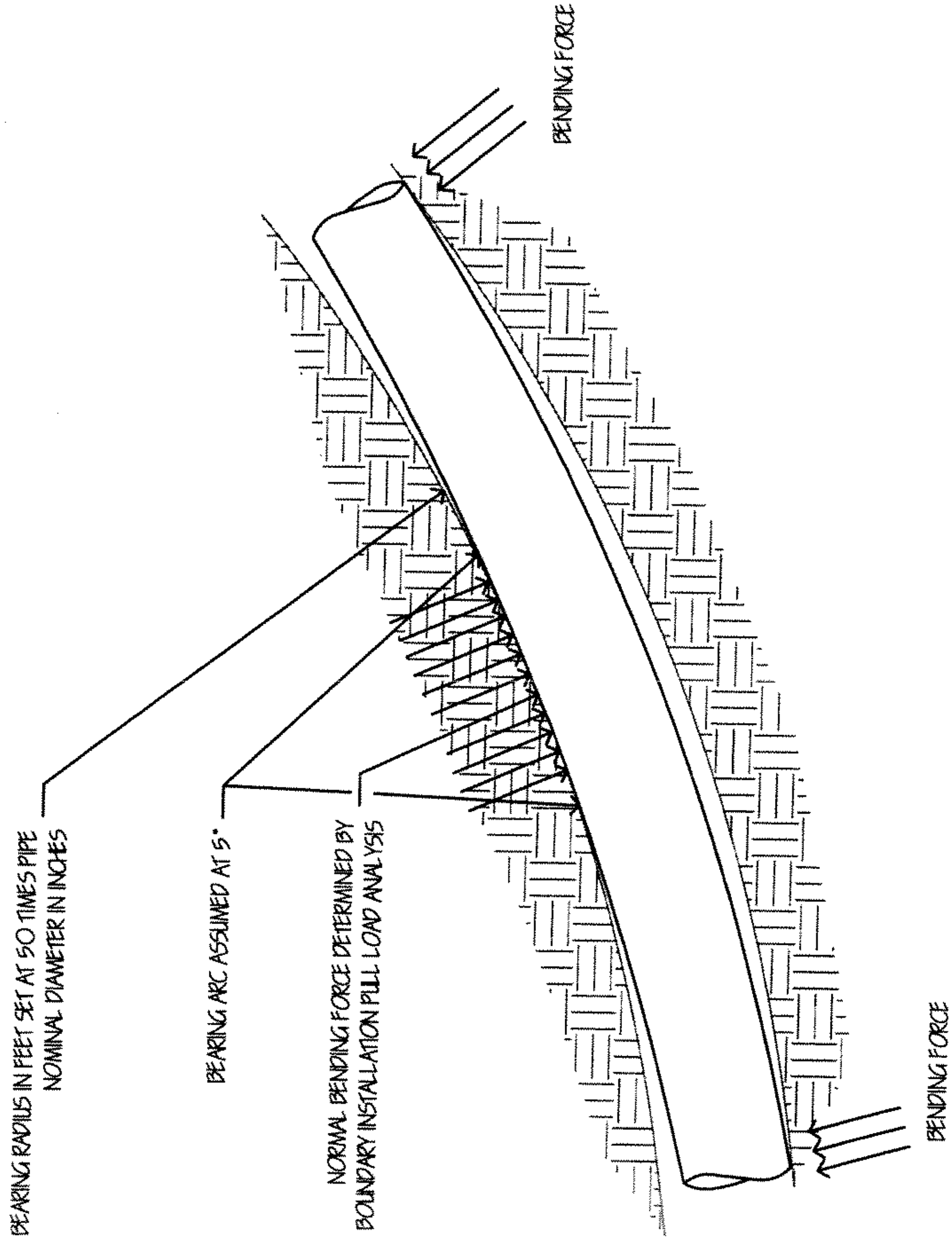
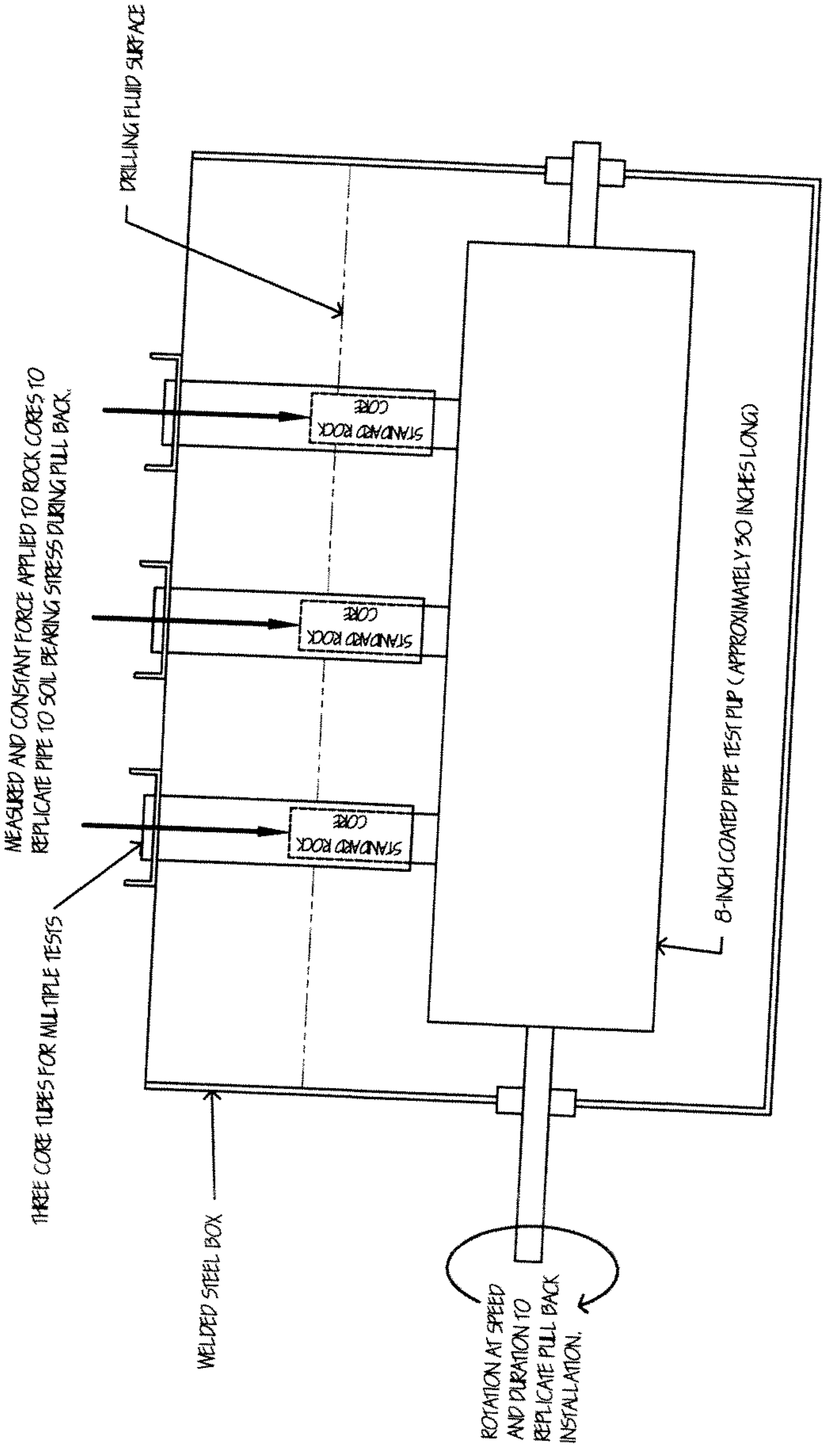
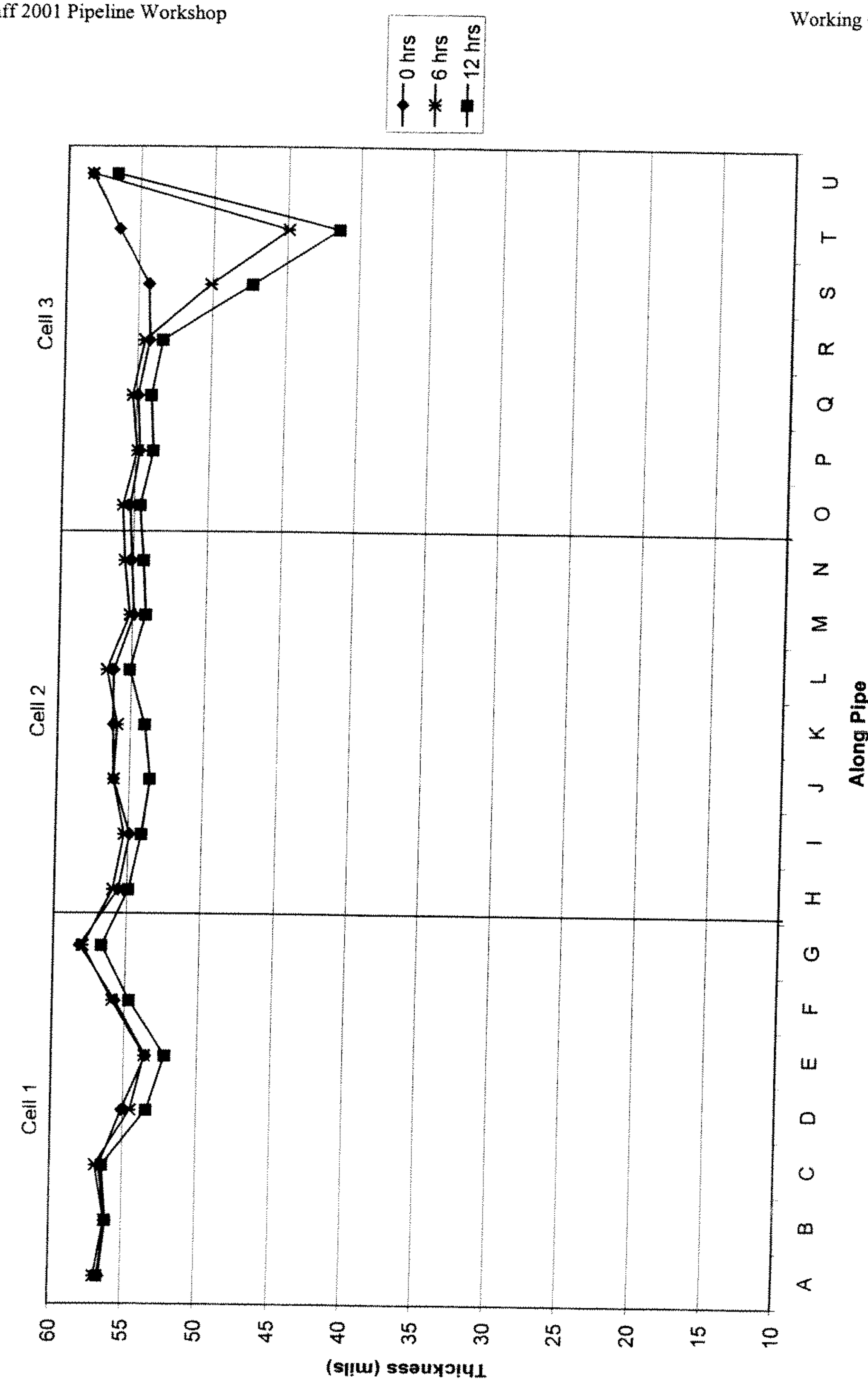


FIGURE 2. BEARING FORCE RESULTING FROM BENDING



CONCEPTUAL DESIGN, ROCK TESTING BOX

Pipeline Research Council International, Inc
Contract No. PR 227-9812



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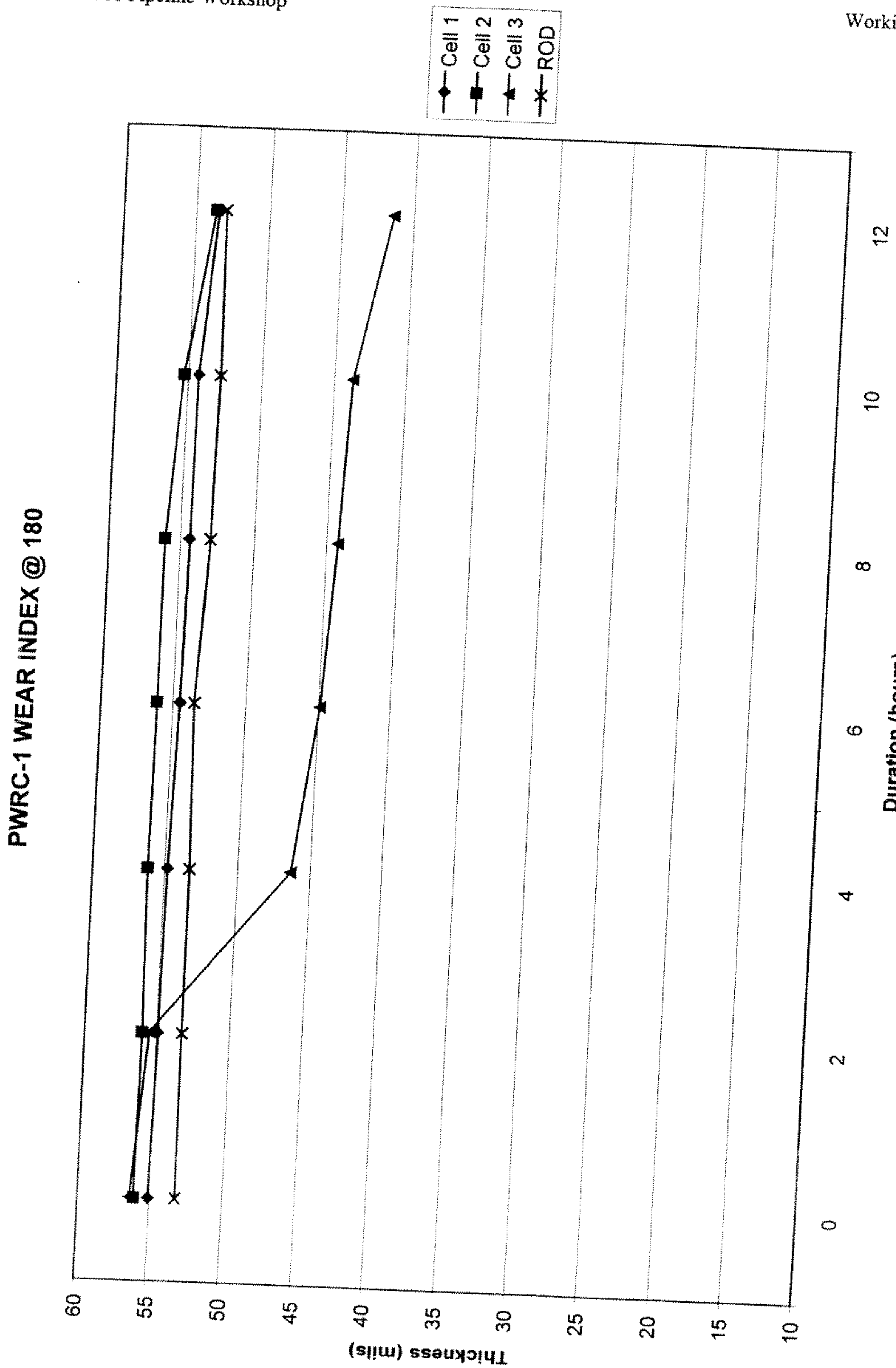
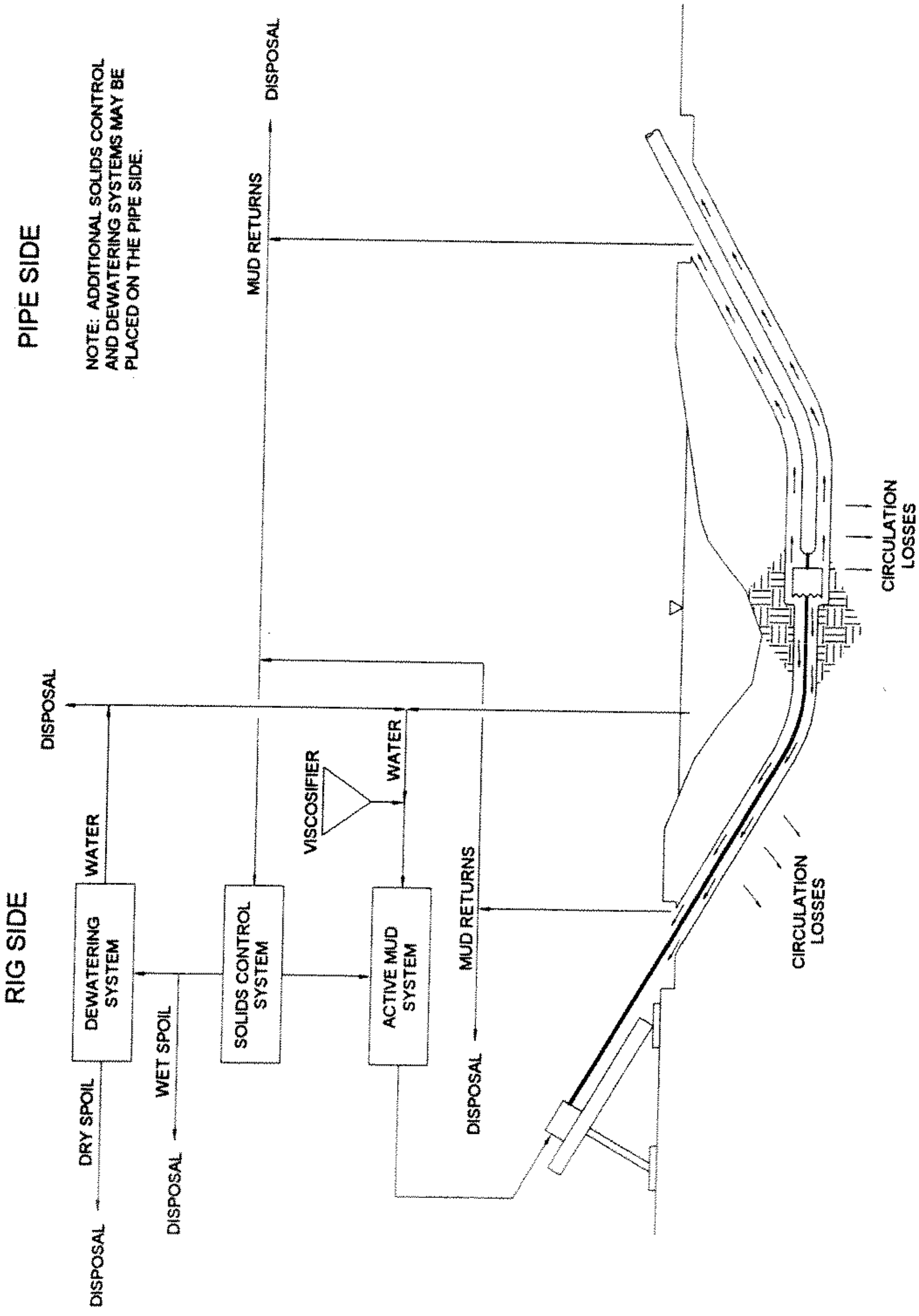
J.D.Hair&Associates,Inc.
Consulting Engineers


PWRC-1 WEAR INDEX @ 180
Cell 1
Cell 2
Cell 3
ROD
Thickness (mils)
60
55
50
45
40
35
30
25
20
15
10
0
2
4
6
8
10
12
Duration (hours)



HDD Drilling Fluid Flow Schematic

Enhancement of a Pigging Program

Banff/2001Pipeline Workshop
Banff, Alberta, Canada
April 9-12, 2001
Barry Nichols
HCI Canada Inc

Why Enhance a pigging program?

- Improve Flow Efficiency
- Improve Inspection Results
- Improved film application on inhibitor runs
- Remove more solids per run
- Reduce differential pressures on runs
- Reduce the chances of becoming stuck on runs with heavy debris

Typical Cleaning Pig Characteristics

- Clean with mechanical force between pig and pipewall
- Push material through the pipeline
- Bypass holes to create turbulence

Typical Cleaning Pig Characteristics

- Brushes good for cleaning pipewalls
  - by design not overly effective at cleaning pits
  - effectiveness determined by
    - shape of brush
    - how brushes are mounted
    - size of brush
    - stiffness of material in brush verses material to be cleaned

Typical Cleaning Pig Characteristics

- Some cup/disc designs better for cleaning
  - effectiveness determined by
    - hardness of material
    - thickness of material
    - shape of contact edge
    - velocity of pig

Typical Cleaning Pig Characteristics

- Not designed to:
  - suspend solids in long fluid columns
  - penetrate solids
  - get deep into the pits in the pipewall
  - coat solids to keep the from sticking to each other
  - bring solids out in a slurry

Case History

- Pipeline History
  - 218 km of 20" pipeline (Toronto to Sarnia)
  - originally in crude service for a number of years
  - line cleaned, tested and switched to refined product
    - gasoline
    - furnace oils

Case History

- Problem
  - line was to be cleaned on stream
  - refined product were being contaminated with fine solids
  - product would have to be put to a storage tank to allow solids to settle
  - product would have to be filtered prior to delivery

Case History

- At least 17 pigging runs were made with aggressive pigs
- 4 to 7 cleaning pigs per run
- velocities were such that line was in turbulent flow
- Line fluids after all this was at marginal spec 1/4 of the way up the pipeline

Case History

- Solution
  - chemical solutions where run
    - one to penetrate material
    - one to suspend solids
  - cleaning pigs were run in conjunction with chemicals
  - job was done on stream

Case History

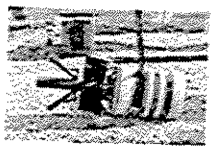
- Solution
  - chemical batch solutions where run
    - one to penetrate material deposit
    - one to suspend solids
  - cleaning pigs were run in conjunction with chemicals
  - job was done on stream

Case History

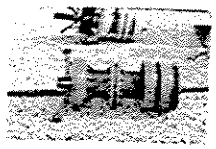
- Results
  - after run #1
    - Line fluids past test 3/4 along the line
    - improved results at the end of the pipeline
  - after run #2
    - Line fluids were about the same condition leaving the pipeline as going in

Case History

Cleaning pig

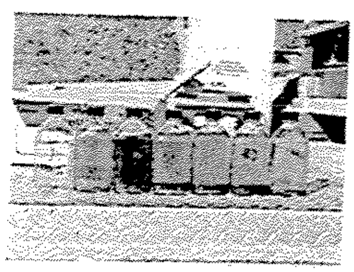


Cleaning pig

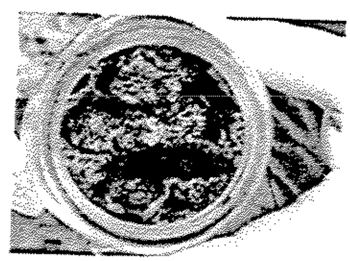


Case History

Case History



Case History



Case History

- Conclusion
  - Solids in the pipeline were not tightly adhered to the wall
  - Fine solids were not being supported by the fluid in the line
  - The chemical solutions were able to suspend these solids

Managing Pipeline Integrity: Construction, Repair and Maintenance
April 10, 2001 10:30 a.m. - 5:00 p.m.

	Company	Name	Phone	E-mail	Signature
1	Suncor Energy Marketink	Brian Dennis	780 449 2108	BDENNIS@SUNCOR.COM	
2	FMChristensen Metallurgical Consulting Inc	Frank Christensen	250 752-1467	fmcmci@home.com	
3	Enbridge Pipelines	Shaun Dawe	780 420 8684	shaun.dawe@cnpl.enbridge.com	
4	Rainbow Pipe Line	Barry Martens	780-449-5856	barry_j_martens@email.mobil.com	
5	Hunter McDonnell Pipeline Services	Denene Geissler	780-436-4400	denene@hmpsi.com	[signature]
6	Dynamic Risk Assessment Systems	Glenn Yuen	403 547 8638	glenn_yuen@dynamicrisk.net	
7	TCPL	Bruce Gray	403-920-6088	bruce_gray@transcanada.com	
8	Pierce Consulting Ltd	Chris Pierce	403-281-8627	cpierce@telusplanet.net	
9	Westcoast Energy Inc	Jennifer Wong	(604) 691-5973	jjwong@wei.org	[signature]
10	KTA-Tator Canada	Linda Gray	780-440-9391	lgray@kta.com	
11	Williams Gas Pipelines West	David Katz	801-584-6911	David.C.Katz@Williams.com	
12	PII	Ravi Krishnamurthy	713-849-6339	krishnamurthyr@pii-usa.com	
13	Transportation Safety Board	Daphne Snelgrove	(819) 953-5728	daphne.snelgrove@tsb.gc.ca	
14	Imperial Oil Pipelines	Lorna Harron	780-955-6177	lorna.harron@esso.com	[signature]
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16	Trans Mountain Pipe Line	Kyla Loewen	780-449-5913	kylal@tmpl.ca	[signature]
17	Marr Associates	David Portelance	403-258-2233	dportelance@marr-associates.com	[signature]

18	Myles Artym	NeoCorr Eng. Ltd	531 1926	myles@neocorr.com	[signature]
19	CLOCK SPRING	PATRICK PORTER.	281 590 8491	pporter@clockspring.com	[signature]
20	Dynamic Risk Assessment	Trevor MacFarlane	403 547 8638	trevor.macfarlane@dynamicrisk.net	[signature]
21	Blair Carroll	Fleet Technology Ltd.	613 592-2830	bcarroll@fleetech.com	[signature]
22	Phil GAUTHIER	Pengrowth Corp	780 333 7109		[signature]
23	BARRY ANDERSON	BCGAS	(250) 868-4572	bwanderson@bcgas.com	[signature]
24	Chris Junger	BC GAS	(250) 868-4571	cjunger@bcgas.com	[signature]
25	BRUNO ORLICZEK	BCGAS	250 868-4568	borliczek@bcgas.com	[signature]
26	LANCE BENGERT	WESTCOAST ENERGY	250-960-2000	lbengert@wei.org	[signature]
27	Gerry Wilkinson	Positive Projects	(403) 235-1650	gerry.wilkinson@positiveprojects.com	[signature]
28	Scott Arndt	Husky Oil	(780) 871-6553	Scott.Arndt@husky-oil.com	[signature]
29	SCOTT IRONSIDE	ENBRIDGE PIPELINES	780-420-5267	scott.ironside@cnpl.enbridge.com	[signature]
30	DARYL WENDLAND	ALLIANCE PIPELINE	780 518 7622	wendland@alliance-pipeline.com	[signature]
31	PETER DONNELLY	Pembina Pipeline Corp.	780-542-5341	pdonnell@pembina.com	[signature]
32	BARRY NICHOLS	HCI CANADA INC	403 391-1335	bnichols@hciww.com	[signature]
33	WAYNE DUNCAN	CSI COATING SYSTEMS INC	780-955-2856	wduncan@csicoating.com	[signature]
34	EARL LEONARD	AIE.UB	780-460-3864	EARL.LEONARD@AEUB.AB.CA	[signature]

35	Rod Charlesworth	EUB	340 5429	ron charlesworth @ gov. ab www.eub.gov.ab.ca	
36	Don Ulsifer	Flint Field Services Ltd	403-342-8066	dulsifer@flint-energy.com	
37	John Craig	Pacific Northern Gas	604-691-5857	jcraig@wei.org	
38	TRENT VAN EGMOND	TCPL	403-920-5893	trent_van_Egmond@ transcanada.com	
39	Don Powell	Corrpro Canada, Inc.	403-235-6400	dan.powell@corrpro.ca	
40	PAT MCNEILL	TRANS MOUNTAIN	250-371-4014	PATMCN@TMPL.CA	
41	Imperial Oil	Doug Adamson	780 955-6159	dougadamson@esso.com	
42	Imperial Oil	Al Forth	905-689-6621	al.forth@esso.com	
43	J. Bruce Nestleroth	BATTELLE	614 424-3181	nestlero@battelle.org	
44	JACQUES EBERLE	HEMPEL COATINGS	(604) 273-3200	sales.ca@hempel.com	
45	LANCE BENGERT	WESTCOAST ENERGY	250 960-2000	lbengert@WEI.org	
46	CENTRA GAS	DON WALLACE	250-751-8319	Dwallace@centrabc.wei.org	
47	Mohammed Jawrah	PII	403-298-2330	jawrahm@pii-canada.com	
48	Francesco Sorrentino	Integrity Service Cons.	905-751-0973	sorrento@aci.on.ca	
49	Roger Vogel	NDT Engineering	+49-7244-7415110	r.vogel@ndt-eng.de	
50	JEFF WARNER	HCI CANADA Inc	(403) 2320456	jwarner@hciwn.com	
51					

52	Glenn Cameron	Greenpipe Industries	403 260 -6748	glenncameron@greenpipe.com	
53	David Feser	Rainbow Pipe Line Company	403 260 7338	david_a-feser@email.mobil.com	[illegible]
54	Chris Hartnell	Hunter McDonnell Pipeline Services	406-698-3318	chrish@hmpsl.com	[illegible]
55	Jill Hopkins	Conoco Inc	(307) 382-4514	jillmhopkins@usa.conoco.com	[illegible]
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Working Group 4
Construction, Repair and Maintenance

Co-Chairs:
Reynold Hinger, Corridor Pipeline Ltd
Mark Yeomans, TransCanada Pipelines Ltd.

Rapporteur:
Greg Hill, Corridor Pipeline Ltd.

Banff2001 Pipeline Workshop 1

Use of Petrosleeves
Kyle Keith, Foothills Pipe Lines
Bob Smyth, Petro-Line

- PetroSleeve - steel repair sleeve
- Foothills carried out a corrosion repair program in 2000
  - 10 Petro sleeves installed
  - 10 Clo cksprings installed
- Cost per foot of sleeve repair was approximately the same
- Advantages/Disadvantages

Banff2001 Pipeline Workshop 2

Use of Petrosleeves Continued...

Discussion/Questions

- CSA Z662 status?
- Why use Petrosleeves versus Clocksprings?
- Petrosleeves and side and sag bends?
- Installation on hot oil pipelines?
- Ditch widths for installation

Banff2001 Pipeline Workshop 3

Directionally Drilled River Crossings
John Hair, JD Hair & Associates

- Drills of more than 1800 metres are currently achievable
- Important Design Considerations
  - De fine Obstacle
  - Surface and Su bsurface Surveys
  - De sign Profile
- Protective Coating Research
- "Inadvertent Mud Returns"

Banff2001 Pipeline Workshop 4

Directionally Drilled River Crossings Continued...

Questions/Discussion

- Bore hole spacing?
- Is casing an option to prevent inadvertent mud returns?
- Polyethylene as a protective coating?
- Pipe Radius?

Banff2001 Pipeline Workshop 5

Enhancement of Pipeline Pigging Programs
Barry Nichols, HCI Canada Inc.

- Advantages of Chemical Cleaning
  - flow efficiency
  - in-line inspection results
  - removal of solids
- Three Case Studies
  - Change in product service
  - Iron Sulphide
  - Wax removal

Banff2001 Pipeline Workshop 6

Enhancement of Pipeline Pigging Programs Continued...

Questions/Discussion

- Internal coatings?
- Can chemical be recycled?
- Slug length?
- Environmental hazard?

Banff2001 Pipeline Workshop 7

Working Group 5 – Stress Corrosion Cracking Hearings + Five Years

Co-chair: Robert Sutherby
Co-chair: Fraser King
Rapporteurs: Katherine Ikeda-Cameron and Greg Van Boven
Facilitator: Doug MacDonald

First Session - NEB 5 Years On

65 attendees, 3 Presentations:

Bob Sutherby, TransCanada Pipelines, Introduction
Doug Waslen for Joe Paviglianiti, NEB presentation
Walter Kresic, Enbridge Pipelines, CEPA presentation

General Discussion

Fraser King [NRTC] Is SCC a dead issue?

Bob Coote [TransCanada] SCC can't be considered a dead issue. Among all those SCC colonies is there any indication of what may lead to failure? Has the effort to date prevented any failures?

Bob Sutherby [TransCanada] # of significant or near critical defects from excavations in the CEPA database is zero. No features have been found to date on excavations that were imminent going to fail. Failures have occurred on hydrotest. Less than 10% deep and not significant is what has been found. Corrosion has a scale that differentiates severity due to rusting or pitting but in SCC when you find chicken scratches all you can do is try to learn from that and extrapolate. Models are being used. We also now find circumferential SCC from inquiry that is being managed, we now have high pH SCC in Saskatchewan and SCC that forms in corrosion.

Tom Pesta [AEUB] noted that there are no CAPP attendees?. Is this an indication that from an Alberta perspective that CAPP doesn't see SCC as important. AEUB issued letter 98-6 to increase awareness by asking companies to submit investigations into what they are doing to CAPP and CEPA. Interim directive is being drafted. SCC on CAPP member companies is associated with tape coatings and asphalt coatings but no correlations with pressure and soil data. Directive says if you have disbonded coating you have to include this in your integrity plan and look at risk associated with this. SCC is an integrity issue that will have to be dealt with just like other integrity issues. CAPP has been good about collecting data.

Jim Marr [JE Marr & Associates] seeing SCC as described (under different conditions and just as variable if not more) and is looking for soil correlations. Changing view point on how we look for SCC and are to open everything, which is an evolution. Continue to develop modeling, enhancing data mining. Consistent data collection is important. Most SCC is chicken scratches.

Steve Lambert [U of Waterloo] What is your success rate during excavations? How often do you find SCC?

Jim Marr [JE Marr & Associates] With tape coatings if conditions are there can find it but then question of severity.

Using CP, dCVG now. Starting to see it in wax coatingwhere we did not before. Improvement from six years ago is like going from Grade 1 to Grade 9. We still expect to find it but are now looking for significant cracks and in different conditions versus how many have been prevented by hydrotest?.

Steve Lambert [U of Waterloo] Are you 50, 80, 90 100% successful in finding SCC?

Jim Marr [JE Marr & Associates] Ranges from 60 to 90 %

Burke Delanty [CC Technologies] NEB CEPA showed.....since inquiry how many failures have been found in service or even hydrostatically tested?

Doug Waslen [NEB] In 1996 there was a failure where SCC was at least a contributing factor but none since on NEB facilities.

Ravi Krishnamurty [PII] There were quite a few advanced SCC found since the inquiry.

Unknown; Larger pipeline population in the United States. How many failures down there?

Jim Marr [JE Marr & Associates] 2 in-service SCC failures in the past six months.

Ted Hamre [Canspec Group] Transverse cracking recently led to leak on a small diameter line not regulated by NEB.

John Craig [PNG] We have had 5 in-service and hydrotest failures in 1996 on a small diameter pipeline. (non- NEB, non AEUB)

John Beavers [CC Technologies] Failure analysis in the United States and Canada are continuing to reflect the industry concern to eliminate critical flaws. Stats show that industry has committed to spending resources on mitigating SCC and not that SCC is dead. Near critical flaws aren't normally found in excavations programs, digs are meant to be investigative and lead to assessing the condition of the pipe.

Corey Goulet [TCP] SCC is not a dead issue. TCPL is applying mitigation processes (in line inspection, hydrotesting) and have found advanced defects – we're dealing with the issue. One SCC hydrotest failure in 2000 on an AEUB regulated pipe. It behooves us all to not ignore this problem. TCPL has prevented a handful of in-service failures in the last 6 or 7 years with hydrotesting.

Steve Lambert [U of Waterloo] public only hears of failures not hydrotest failures or inline inspection data. What does CEPA do with hydrotest failure data and critical feature data?

Walter Kresic [Enbridge Pipelines] 99.9% of CEPA SCC data entered is chicken scratch which therefore forms the majority of the correlations. Data forms part of knowledge base (data base) but not enough has been collected to say anything about critical cracking.

Steve Lambert [U of Waterloo] Should the public know this more positive knowledge?.

Walter Kresic [Enbridge Pipelines] Yes, we need to draw out the more positive statements and communicate them.

Bob Sutherby [TCP] We should say what we haven't found as well.

Fraser King [NRTC] Liquid versus gas susceptibility. Any difference in susceptibility?

Greg Toth [Trans Mtn Pipeline] SCC not dead. Programs much more mature. Just one more hazard to assess. Residual stress – SCC related to corrosion. We find SCC related to residual stress.

John Beavers [CC Technologies] Metallurgical evaluation with near neutral pH (CEPA program) the single factor with strongest correlation on gas lines was residual stress. SCC colonies were found in areas of high residual stress. In liquid lines SCC occurs where significant corrosion, wall loss or locations where residual stress are increased.

Fraser King [NRTC] Is there an affect of different modes between liquid and gas lines (eg. batch or continuous)?

John Beavers [CC Technologies] Lower R ratio sees more crack growth. Is this SCC or corrosion fatigue? Observation that more cracking on liquid lines, I don't understand it.

Steve Lambert [U of Waterloo] As a researcher I don't understand why liquid lines are less susceptible. Some statistics are biased because of more digs. Liquids lines should be considered.

Jim Marr [JE Marr and Associates].We're beginning to see just as much SCC on liquid lines as gas and as severe. Primarily non-classical. Doing more work on liquid lines. Looking more often. Using CEPA guidelines.

Ravi Krishnamurty [PII] I see a systematic trend, higher pressure deeper cracks and in last 6 months have seen at least 2 or 3 liquid lines in warmer southern states with substantial cracking. Dependent on cyclic loading and coatings.

John Beavers [CC Technologies] Any high pH SCC on a liquid line?

Jim Marr [JE Marr] Only near neutral pH SCC.

John Beavers [CC Technologies] defines the difference between high and neutral SCC. High pH SCC is primarily intergranular, high pH solution associated with little or no corrosion, concentrated bicarbonate solution. Near neutral pH SCC is transgranular, found under tape coatings, shielding of CP or inadequate CP, frequently associated with corrosion and near neutral dilute solutions.

Ray Fessler [BIZTEK] One difference is high pH SCC is sensitive to temperature where near neutral pH SCC is not temperature dependent. In gas lines higher temperature at compressor stations have distinct non random distribution of SCC. Liquid lines are less susceptible to high pH SCC. The probability is much lower of finding high pH SCC on liquid lines.

Fraser King [NRTC] Are there any individuals who have seen changes since NEB hearing?

Bob Sutherby [TC] Who was involved in SCC issues at the time of the NEB hearings?
½ of room
Is everyone comfortable with language, cracking morphology?
Did inquiry change the focus? Has it changed the way we do things? Is SCC a bigger issue now?

Tom Pesta [AEUB] Knowledge of SCC has increased as a result of inquiry. Before that limited to transmission lines, now SCC can be found upstream and in other areas.

Bob Sutherby [TC] Contractors are still seeing work with SCC. Comments from contractors as to what the inquiry has done for them?

Ravi Krishnamurty [PII] after inquiry 2 things came out. Upstream started to look at SCC. And other ways were looked at – more aggressive tool vendors were going after inspection technology. More work in US as well. This will position us better in dealing with SCC in the future.

Bob Sutherby [TC] What about in another 5 years?

Ravi Krishnamurty {PII] Fewer failures, better position

Doug MacDonald [SNC Lavalin] Perceived lack of understanding of SCC is what started this workshop in 1993. We've come a long way.

Bob Sutherby [TC] What about concerns with contact damage, internal and external corrosion? Is SCC a small component of big picture?

Walter Kresic [Enbridge Pipelines] The fear of the unknown is gone. We don't know all the hows and whys but we have more tools to keep industry safe. We are managing the child (since the birth)

Steve Lambert [U of Waterloo] Yes SCC was a concern because we didn't know that much. Industry and NEB have done a good job in putting in procedures. SCC is ahead in how we handle the problem and getting industry to act effectively. Still bigger hazards out there.

Bob Sutherby [TC] Perception between first and second inquiry was that SCC was getting worse, just tip of the iceberg. The potential hasn't grown a whole lot over the years.

Tom Pesta [AEUB] SCC work is more defined. Understanding is that SCC is on many different pipelines and now we are evaluating the risk. Chicken scratches will not result in ruptures. Perception was that ruptures were the only outcome but now it is perceived that there is less risk.

Bob Coote [TC] SCC is still of great interest. The methods available for detection, to give the operator confidence, are not yet available. Maybe hydrotesting. Great hopes for inspection technologies to help us manage SCC.

Corey Goulet [TC] Hydrotesting only one method. Liquid crack tools are advanced technolgoy and will eventually be available for gas. EMAT scan tool is progressing. This is why continuing research is necessary - develop more cost effective mitigation methods.

Fraser King [NRTC]– Is the public safer?

Bob Sutherby [TCP] Is SCC perceived to be only a big company issue relating to big inch pipelines?. Is there not a problem with smaller diameter pipelines?

Tom Pesta [AEUB] Quote from CAPP letter - downstream pipeline demonstrates sufficient risk for SCC (acknowledges issue). Upstream does not possess significant risk. Will maintain data base.

Fraser King [NRTC] Risk as opposed the susceptibility to SCC.

Bob Sutherby [TC] 600 to 800 failures a year, how many SCC?.

Tom Pesta [AEUB] We do not know because the AEUB data does not identify this.

Stan Wong [CC Technologies]. SCC hasn't gone away. Have a better handle of SCC as a threat relative to other threats. Corrosion bigger and higher frequency threat on smaller diameter pipelines

Bob Sutherby [TC] Vigilance but not actively looking on small inch diameter lines. Transportation Board had wanted to reduce pressure. This would have cost billions of dollars but research has shown that this would be a short term solution at best.

Fraser King [NRTC] Any last comments before break?

Yes public feels safer.

Second Session - *SCC Site Selection Models*

57 attendees

Bob Sutherby [TC] Introduction

Issues from 1999 session
What are people using models for, role of models
Refocus

Discussion

Steve Lambert [U of Waterloo] Point of clarification. Deterministic should have been empirical, based on correlations/observations or based on some understanding of the mechanism? What do experts base their models on?

Jim Marr [JE Marr] Our models are based on observations from excavation programs. Apply terrain data to pipeline conditions. Extrapolate this to other similar conditions on pipeline. Empirical.

Steve Lambert [U of Waterloo] Any mechanistic models?

Bob Sutherby [TC] What about pressure?

Jim Marr [JE Marr] Other aspects of operating pipeline are being included in models, temp, R ratio, metallurgy. Focussed on correlations of terrain conditions; it worked but are now refining it to get better conclusions. Bringing in ILI, CP data to help locate areas of disbondment. Refinement. Used to use soil models before now use more data.

Glen Cameron [GreenPipe] We use GIS and Jim's soil model, elevation maps, pressure, aerial photos. Going down road with everything and will see if get empirical model.

Barry Martens [Rainbow Pipeline]. ILI will miss as much as soil model. First program with Jim Marr there were 16 areas that detected minor SCC. Started using CD Ultrascan tool and found deep SCC. Still used soils model because it finds the start of SCC but will the model take you to the more severe? Used field observations of tape disbondment etc. but didn't find SCC necessarily on similar areas. Now considered wrinkles and trapped water against pipe. Found free flowing water didn't propagate SCC so now use trapped water criteria. Well drained soils found severe SCC. Water table fluctuations would trap water. Can't predict this but look for the same scenario – SCC in corrosion.

Bob Sutherby [TC] Are you learning from your own experiences?

Barry Martens [Rainbow Pipeline] Metal loss corrosion with severe SCC – can't find with tool.

Bob Sutherby [TC] Sometimes we find all corrosion on one side of pipe.

Barry Martens [Rainbow Pipeline] TRAPIL presentation of asphalt coated line, SCC at 10 and 2 o'clock position; Rainbow finds it at 5 and 7 . Disbondment catch the water when it fluctuates. On Rainbow tape on the top half is tight with TRAPIL they find their SCC on top opposite. Makes sense.

Jim Marr [JE Marr] Where would operators be without models before other things were available? At time of hearings they were quite valuable. Models can be useful for decision making, optimize cost benefit and maintain pipeline integrity. Rainbow's model works –have compiled data and used info for making better decisions.

Stan Wong [CC Tech] Experience from 1930's vintage, combination of deterministic and mechanistic. Quality issues around construction practices.

Steve Lambert [U of Waterloo] What is the focus on where models are going? Models are useful and have done good. How does the severity of SCC work into the model? We know there is a lot of SCC. Fine tune models to pick out worst SCC. Will in-line inspection make models obsolete?

John Beavers [CC Tech] Severity vs occurrence. Can't use soils model to predict severity. Good news is that there is not a lot of severe SCC with near neutral SCC. Use all types of input data (manufacturer etc.)

Bob Sutherby [TC] What else can we look at?

Stan Wong [CC Technologies]. Early construction practices highlighted problems. Circumferential SCC caused by construction practices of the day.

Reg Eadie [NRTC] You are looking for intersection of two sets. Topography of water/wrinkles and change from chicken scratches to severe. Several techniques, models, ILI, hydrotests. Need both or all techniques. Missing factor is extra stress, bends, residual plus susceptible conditions. Intersection of conditions for severe cracking is rare.

Barry Martens [Rainbow Pipeline]. Not much success on 20 inch line when dug on soils model or when dug on corrosion loss. CP was found to be going through outer wrap. Picoflex coating. Soils model were not responsible just condition of pipe.

Presenter
Keith Leewis- GRI "Direct Assessment"

Bob Sutherby [TC] What do you need to put into the model?

Keith Leewis [GRI] History, land forms, soil types, chemistry to relate data. Bottom of hills, coating, these are all indirect measurements then you need to dig and find the truths.

Barry Martens [Rainbow Pipeline] If disbonded coating doesn't have a chance for water being trapped ie the disbondment doesn't reach the edge of the tape, is that wrinkle put in to the assessment?

Keith Leewis [GRI]. May find that you need to dig in places where you don't think you have SCC and determine that – need to validate the predictions with the truth (digging the pipe)

Bob Sutherby [TC] What are direct assessment expectations?

Keith Leewis [GRI] Expectations to help NACE committee out in integrity management plan.

Walter Kresic [Enbridge Pipeline] Why the word *direct* assessment?

Keith Leewis [GRI] That word was chosen by regulator. Need to touch the pipe to take measurements and to validate.

Wenyue Zheng [Canmet] What kinds of things do you look for in chemistry of soils?

Keith Leewis [GRI] General clay and moisture content. Each company has found own experiences and should look to CEPA for the definitive answer.

***Presentor* - Scott Ironside [Enbridge Pipelines] "SCC Monitoring Program"**

John Craig [PNG] Is 34 inch most susceptible?

Walter Kresic [Enbridge Pipelines] 50% of line is tape therefore susceptible. Less susceptible on asphalt.

Barry Martens [Rainbow Pipelines] Is there something that could constitute a change? Bigger companies need to guide smaller companies with their knowledge. We rely on these companies for direction.

Walter Kresic [Enbridge Pipelines] Based on all the work we've done, SCC is everywhere but not severe. We feel confident to say our pipeline is safe whereas we couldn't have said that in 1995.

Barry Martens [Rainbow Pipelines] What is different about models today that will guide me to the more severe SCC? Any changes that can direct me?

Walter Kresic [Enbridge Pipelines] No panacea. Need models and this would be important to companies just starting. We use all technologies – know that SCC risk is low.

Barry Martens [Rainbow Pipelines] What can a 12 inch pipeline company learn from you?

Keith Leewis [GRI] No silver bullets. Need to do it for your own system. If another company finds a strong correlation it may or may not work for other companies.

Barry Martens [Rainbow Pipeline] Industry follows a few companies and relies on them for new information. Need to disseminate info to help small operator that doesn't have money, tools, etc who could still have a rupture that could hurt someone.

Bob Sutherby [TC] CEPA database is a source of information. Nine company members. Need to continue to gather information and trend it.

Stan Wong [CC Technologies] Bigger companies making available mechanistic info. In-house deterministic model mixed with mechanistic model in lieu of pigging for smaller diameter companies.

Steve Lambert [U of Waterloo] Bigger companies can take models to next level. Did ILI make changes to your model? How does this filter down to smaller companies?

Walter Kresic [Enbridge Pipelines] No changes yet have been made to the landscape models from ILI data. Doesn't matter where you are you can find SCC. FBE and properly applied coatings are far less susceptible – good info for decision making. All additional data will incrementally improve your individual companies decision making process.

Steve Lambert [U of Waterloo] As a small operator – you can't tell me where severe SCC is? With more ILI you should be able to correlate soils model better.

Walter Kresic [Enbridge Pipelines] Maybe that will happen.

Glen Cameron [GreenPipe] Populated area – consequence of failures should be incorporated. That's what we are going to use in the GIS world.

Keith Leewis [GRI] Models should not be thrown away. Need all the tools in your toolbox. Models and direct assessment need to feed each other.

Stan Wong [CC Tech] On small diameter – have their been any significant SCC on 16 inch or less?

John Craig [PNG] has had 5 hydro failures and 2 in-service failures on ERW pipe.

Glen Cameron [GreenPipe] Yes we found SCC on a 10 inch liquid line (from excavation)

Curtis Parker [Trans Gas] Limited amount of SCC on 12 inch and 16 inch pipe.

Bob Sutherby [TC] Rimby failure? SCC or mechanical damage? I want to be clear on what we call these things.

Barry Martens [Rainbow Pipeline] Mechanical damage can mean wrinkles. Can this mechanical damage lead to SCC.

Fraser King [NRTC] Closing comments.

- Validation -

Direct Assessment External Corrosion

Keith Leewis, GTI

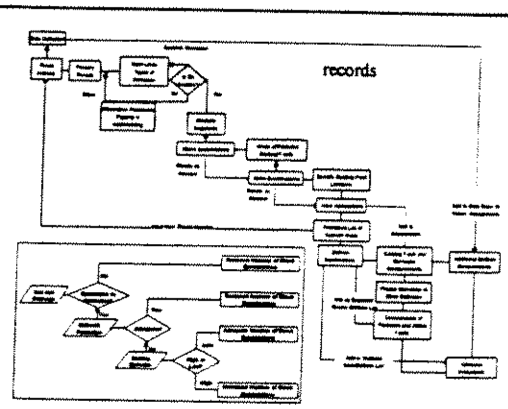
March 2001

Direct Assessment

- Alternative to Pigging & Hydro in HCAs
- Provide NACE with justification & draft language for a new standard
- Operator Gathers & Integrates Data
- Operator Provides the DA Output
- Validation Report - Battelle

An Integrity Process
(not a tool)

- DA requires the integration of all three
  - alignment sheet information (GIS)
    - facilities
  - historical records, DOT incident etc
    - repairs, leaks, coating reports, etc
    - digs at concerns & were OK
  - above ground inspections
    - voltage (CIS, Annuals)
    - current (DCVG, C-Scan, ACVG, PCM)
    - historical records - changes in CP system



Use the Right Tools

- No Blindly Applying Vice Grips to Nuts
- Use the Direct Assessment Process Matching Tool(s) to the Threat
- DA Works
  - CP Prevents Corrosion
  - Regs Require Annual and CP Inspections
    - Annual Leaks Continue to Dropped 60% since 1985

Direct Assessment
Validation Report

- Field Inspection Work
  - Conduct Continuous Inspection(s)
  - Use the DA Process to Determine Locations
    - Yes, Moderate, No
  - Digs provide the Truth
- Document DA Process Decisions
  - When DA Appropriate & Not
  - Integration (Paper & Electronic)
    - Facilities, CP Inspections, & History (All three)

Direct Assessment
Pipeline Integrity Comparison

DA Outcome

	Y	M	N	?
Yes	X			
Mod		X		
No			X	
Missed				X

Coating Damage

Pig Report

	B	M	S	?
BIG	X			
Medium		X		
Small			X	
Missed				X

Wall Loss

Pig Validation

- Expect 1/3 will have corresponding MFL
- Place DA Yes's on top of Pig Yes's
- Explain why
  - DA found coating damage but Pig missed
  - Pig found wall loss but DA missed

DA DA DA DA

Pig Pig Pig

Correspondence with MFL ILI Assessment *(Wall Loss)*

- Bad, Medium, Small, & Missed
- Check vs Bell Hole (Truth)
- Can't find active corrosion only total wall loss from day one
  - One to One Correspondence with DA Impossible
    - DA Estimates Active Corrosion - Proactive & Regs, Looks Now
    - Pigging Estimates Deep Wall Loss - Reactive, Looks Back

Direct Assessment
Timeline

- Direct Assessment Standard in NACE
- Validation & Reporting
  - May 1st for 20 data participants
  - June 30 for submission of all data
  - June 30 to complete funding
  - Sept 30 for draft report of the validation
  - Dec 15 final report due

Direct Assessment
Confidentiality

- Ed Ondak & Greg Hindman - the OPS Witnesses
- Baseline Tech - Info Gathering and Organizing
- Battelle - Statistical Proof, Documentation
- Aggregate in Report has No ID Location
- Company Data Returned

Direct Assessment
Funding

- FERC (GRI & PRCI) $180K approved
- OPS $180K solicited
- Other Participants $600K soliciting
- Management by INGAA Pipeline Safety
  - GTI Prime, subcontracting to
    - Baseline - data gather/migrate to electronic files
    - Battelle - Statistics and Report
    - Paragon, CCTechnologies, GTI - confirmation

BANFF/2001
PIPELINE WORKSHOP

SCC Monitoring Program
Scott Ironside
Enbridge Pipelines Inc.

April 9-12, 2001 Banff 2001 Pipeline Workshop ENBRIDGE

SCC Monitoring Program Components

- **Predictive Models**
  - Soil landscape models
  - Coating type/condition
  - Operating pressure characteristics
  - Cathodic protection information
  - Location w.r.t. population density
- **Hydrotest**

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SCC Monitoring Program Components

- **Maintenance Excavations**
  - Has SCC been found in this area before?
  - Periodic monitoring of locations where SCC is found
- **ILI Data**
  - Crack Detection data
  - Corrosion data

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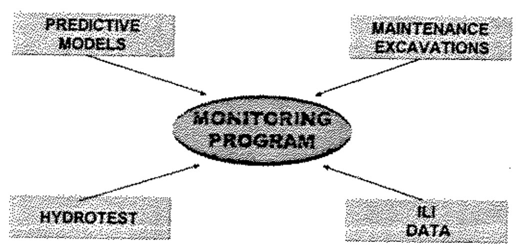
SCC Monitoring Program Components



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PROGRAM CONTINUATION

- Evaluate the current tools we have available
- Identify improvements that are required
- Determine the applicability of these tools within our monitoring program
- Search for additional technologies that may be useful

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BANFF/2001
PIPELINE WORKSHOP

SCC Hearing + Five Years

Robert Sutherby
TransCanada PipeLines

Fraser King
NOVA Research & Technology

April 9-12, 2001 Banff 2001 Pipeline Workshop

Objective

- Create a refocus of issues
- Not expecting any definitive answer ...
- What has been the benefit of The Hearing?
- Sense of progress or situation

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History

- Following TCPL SCC failures
- First Inquiry 1992 (MHW-1-92)
- Additional TCPL ruptures
- Second Inquiry 1995 (MH-2-95)

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Hearing Issues

- **Extent and severity in Canada**
- **Status of research**
- **Detection of SCC**
- **Mitigation Measures**
- **Prevention of Initiation**
- **Safety & Protection of Environment, Property**

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Five Years On ...

- What is the significance of '5 Years'?
- Are we 5 Years better?
  - better at preventing SCC?
  - Is the public safer today than 5 Years ago?
- Pipeline systems are 5 Years older
  - significance of 5 Years more age?
  - 5 Years more issues

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Perspectives

NEB Doug Waslen / Joe Paviglianiti

CEPA Walter Kresic
Chair, Pipeline Integrity Working Group

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**BANFF/2001
PIPELINE WORKSHOP**

Stress Corrosion Cracking (SCC)
The National Energy Board Inquiry (MH-2-95)
Five Years Later

Joe Paviglianiti, P.Eng & Doug Waslen, P.Eng.

April 9-12, 2001 Banff 2001 Pipeline Workshop

?????????????

- Somebody recently told me that SCC is a dead issue.

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Outline

- Inquiry Report
- Post-Inquiry
- SCC Liaison Group
- Ongoing Activities
- CEPA Trending
- What's New
- Plans and Priorities

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Inquiry Report
Recommendations in 6 Key Areas

- SCC management program for all pipelines
- Changes to the design of pipelines
- Continued research
- Establishment of SCC database
- Improved emergency response practices
- Continued information sharing

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Post-SCC Inquiry

- SCC Inquiry Report
- NEB SCC Liaison Group
- Community visits
- SCC Management Plans submitted by All NEB regulated companies & reviewed
  - Meetings with 4 companies

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NEB SCC Liaison Group

- CEPA/CAPP/CSA/EUB/BC O&GC and NEB
- Monitor progress of implementation of recommendations
- SCC research - funding
- CEPA/CAPP SCC database & trending

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NEB Ongoing Activities

- Qualitative Risk Ranking of Compan ies SCC Susceptibility
- SCC Management Pl an Updates (1999)
- Company Meetings
- NEB SCC Liaison Group

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CEPA 2000 SCC Database T rending Report Results

Fluid	Length Inspected (m)	No. SCC Colonies Detected
Gas	125,855	17,925
Liquid	20,532	366
Total	146,387	18,291

- Approx. 300 cases of significant SCC reported to the NEB

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What's new?

- Residual stress
- Concrete weights and asphalt coating
- Circumferential SCC
- High pH SCC in Saskatchewan

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What's needed?

- More SCC res earch?
- Is ILI technology improving quick ly enough?
- Need clarification regarding termino logy associated with EAC mechanisms?
- Are predictive models reliable?

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Plans and Priorities - NEB Operations Compliance Team

- Continue to meet w ith companie s
- Continue to monitor in cidents
- Integrate SCC Management with Integrity Management Program audits
- Continue to monitor SCC sc ene

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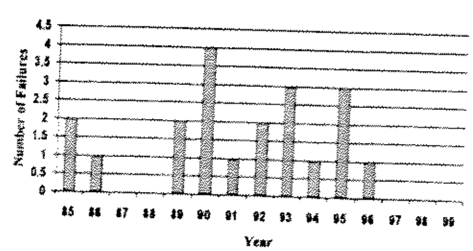
Pipeline SCC Failures



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Somebody recently told me that SCC is a dead issue.

- At the NEB we still feel that it is an issue that requires continued monitoring as part of an overall integrity management plan.
- Do you and your company think SCC is not a problem?
- Are you managing it effectively?

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BANFF/2001 PIPELINE WORKSHOP

SCC Hearing + Five Years
The CEPA Perspective

Walter Kresic, Enbridge Pipelines
Chair, CEPA Pipeline Integrity Working Group

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Industry Accomplishments

- **Defined State of Industry**
  - 1995 SCC Inquiry
- **Industry Guidance**
  - CEPA Recommended Practices
- **Enhanced Collaboration**
  - National / International Agencies

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Industry Accomplishments *(con't)*

- **Formalized Processes**
  - CEPA Data Collection
- **Continued Improvements**
  - Research Projects
- **Disseminate Knowledge**
  - Trend Reports
  - Public Presentations

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Five Years On ...

- Are we 5 Years better?
  - better at preventing SCC?
  - Is the public safer today than 5 Years ago?
- Pipeline systems are 5 Years older
  - 5 Years more issues
  - what is the significance of 5 Years more age?

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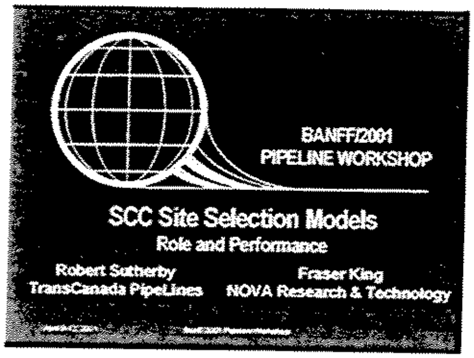

1999 SCC Summary

Evaluation of SCC Defects

- SCC in Corrosion
- Bacteria associated with SCC
- SCC is proportional to tape application
- How to document dig observations
- Role of hydrogen and microstructure
- SCC at/near weld seams
- Liquid and Gas lines
- CEPA data base

SCC Site Selection Models

- background & objectives
- roles & components
- expectations of performance
- future of models

Evolving SCC Scope ...

- Near-neutral pH (Non-Classical) SCC
- High-pH (Classical) SCC
- Toe Cracks
- Circumferential SCC
- Cracks in Corrosion
- Other environmentally-assisted cracking

Objectives

- Create a refocus of issues .....
- What are models to <u>you</u>?
- What goes into models?
- What do we use them for?
- Do / Can models meet our expectations?
- What is the future of models?

Background

- CANMET Workshop 1989
  - based on TCPL ruptures and digs by TCPL and NOVA
- Correlations
  - Tape
  - Soil Texture: Heavy Clay
  - Drainage: Imperfect to Poor
  - Topography: Depressional or Slope Toe

Background

- Reference to an "SCC Soil Model" in the 1996 SCC Hearing
  - deterministic based on excavations
  - "to identify areas of potential susceptibility"
- Recommendation 4-2: " ... develop a predictive model to identify and prioritize sites ..."

Background

- CEPA SCC Recommended Practices (1997)
  - "SCC Predictive Model"
  - Terrain, Pipe Design, Coating Condition, etc.
  - Condition Monitoring

Background

- Alberta Energy & Utilities Board
  - Information Letter 98-6
  - polyethylene tape, asphalt or coal tar
  - hoop stress > 45% SMYS
  - installed 1968 - 1973

Background

- "Direct Assessment"
  - to comply with U.S. Federal Law
  - INGAA developing
  - remote inspection information to provide an "equal measure of pipeline integrity with pigging and hydrotesting"
  - Keith Leewis of the Gas Technology Institute

SCC Site Selection Models

- Why are we discussing models? Why are we not teaching models?
- Models embody your knowledge of your system based on your experience
  - age, region, fluid, operation, coatings, etc.
- Correlations and Mechanisms may be portable
- Entire Models may not be ...

Model Considerations

- Deterministic or Mechanistic
- Portable
- Different Coatings and Conditions
- Correlation to failure?
- Applicability to different forms SCC?
- Who develops models?

Roles of Models

- Regulatory 'Compliance'
- Integrity Management
- Due Diligence
- Risk Assessment
- Research Tool
- Other?

Objectives

- Create a refocus of issues .....
- What are models to you?
- What goes into models?
- What do we use them for?
- Do / Can models meet our expectations?
- What is the future of models?

Managing Pipeline Integrity: Stress Corrosion Cracking
April 11, 2001 8:30 a.m. - 12:00 p.m.

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Managing Pipeline Integrity: Stress Corrosion Cracking
April 11, 2001 8:30 a.m. - 12:00 p.m.

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44	[illegible]	[illegible]	[illegible]	[illegible]	
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SCC Working Group Summary

- NEB Hearings - 5 Years On
- 5 years wiser? Or 5 years older pipelines?
  - Bob Sutherby (TCP) NEB hearings background
  - Doug Waslen (NEB) summary and recommendations from hearings
  - Walter Kresic (CEPA) gave the industry response to the recommendations
  - In 1993, SCC was one of the major issues that prompted this workshop, and now we are in a position to ask.......

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SCC Working Group Summary

- Is SCC a dead issue? Consensus says No!
- But the "fear of the unknown" is gone
  - at least from perspective of liquid lines with in-line inspection tools
  - dry gas lines still waiting for improved technology
  - In-Service failures have been largely prevented by proactive actions

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SCC Working Group Summary

- Liquids versus Gas led to a difference in opinion on perception of risk
- Some say equal susceptibility
- Some say liquid lines are less susceptible
- Good topic for next workshop
- SCC on upstream lines
  - upstream under-represented (scheduling conflict)
  - do upstream companies see SCC as an integrity issue?

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SCC Working Group Summary

- Should the Canadian Public feel safer now than they did 5 years ago?
- Yes, but require continuing vigilance and education

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SCC Working Group Summary

- SCC Site-Selection Models
  - What are they? What are they used for? What are our expectations? What is the future?
  - Bob Sutherby (TC) Background to models
  - Keith Leewis (GTI) Direct Assessment
  - Scott Ironside (Enbridge) Landscape models with ILI
  - current models do not predict severity, just occurrence

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SCC Working Group Summary

- Evolution in Models
- More focus on predicting deeper cracks
- More types of info being incorporated
- Models must be company/line specific
- But companies should share experiences!
- Direct Assessment
  - Formalized U.S. initiative (int/ext corrosion, SCC)

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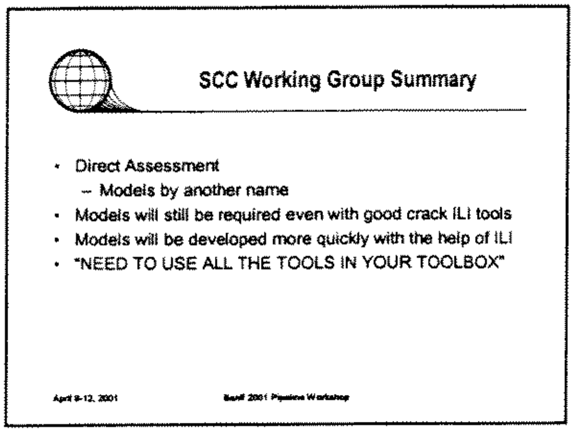
SCC Working Group Summary
• Direct Assessment
– Models by another name
• Models will still be required even with good crack ILI tools
• Models will be developed more quickly with the help of ILI
• "NEED TO USE ALL THE TOOLS IN YOUR TOOLBOX"

Working Group 6 - Coatings
Wednesday, April 11, 2001 at 10:30 a.m. – 5:00 p.m.

Co-Chair: John Baron, Skystone Engineering
Co-Chair: Doug Waslen, National Energy Board
Rapporteur: Kelly Mabbott, Skystone Engineering

Introduction and Objectives of the Session

- Approximately 90 people attended the workshop.
- The objectives of this session include:
  - Update issues identified in 1999 coatings workshop
  - Discuss proposed changes to the CSA Z662 code for coatings
  - Define Cathodic protection compatibility with coatings
  - Address field assessments of in-service coatings
  - Qualification of coatings for high temperature applications
  - Quality of field applied coatings
  - Discuss selection and application of repair and rehabilitation coatings

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Presentations

Paper #1: Doug Waslen (NEB)

- **Proposed Changes to CSA Codes**
- Changes should be published in 2002
- NEB SCC inquiry report stated to develop standard tests and incorporate these tests
- Work started in1998
- Do tests determine performance over the life?
- Reduce variables
- Five areas of the team
  - Assess coating suitability
    - Pipeline Design, Construction, operation, Coating application, Service changes, interaction with different coatings, coating storage
  - Test the coating
    - Isolate from the environment, adhesion, ductile, strength and adhesion, resist degradation, compatible with CP
  - Application and QA
    - Documented procedures for shop and field applied coatings. (QA test, personnel standards and application)
  - Re-assess coatings in formulation or manufacturer or location of manufacturer
  - Re-assess coatings for change of Service for the pipeline
    - Change in service, change in temperature
  - Coating Selection, Assessment, Application and Inspection

Discussion and Question

- Tom Weber (Trenton) – Is this document going to have minimum criteria?
  - No. Liability of CSA. Must update the criteria. Some controversy and arbitrary.
  - John Baron (Skystone). The changes to CSA represent a new approach that involves up front engineering to avoid last minute selections.
- Mike Reed (TMPL) – What about replacements. Do we need to assess the coating for every minor repair?
  - Assessments are specific to coating products under certain applications
- Jim Banach (SPC) – How do you audit a system with no criteria?
  - That is difficult. It comes down to professional judgment.
  - The assessment of the coating could be audited
  - Can you tie short-term tests into long time performance? Is there anything published with a minimum time required?
  - No. It is up to the design of the pipeline. No minimum amount of time is stated.
- Linda Gray (KTA Tator) – How do you handle new products? How do you set criteria now for future possibilities?
- Glen Macintosh – When does this take affect?
  - Once it is approved by the CSA technical committee, it is basically waiting to be published.
- Jacques Eberle (Hempel Coatings Canada) - Why do you have to re-assess if you change the manufacture location. One plant to another.
  - It is a QA issue between plants.
- BC Gas – Application of this new practices, I'm I responsible for a good coating throughout the pipelines entire life. That is tough to do.
  - Assess the factors listed in CSA. The requirement to assess these factors in conjunction with service life is not required.
  - The possibility of service changes should be looked at.
- How do I certify that the coating meets the end use? I will not go out and test 100 coatings for one pipeline. I will leave it up to the coating manufactures.
  - Regardless of who selects the coating, the accountability in meeting CSA is still on the owner. This is consistent with current requirements.
- Becky Morse (Charter Coatings) – Almost impossible to compare coating to coating due to testing differences. The new CSA requirements will help.
- Neil Hay (Koch) – New requirements for application procedures are included in the new CSA revisions.

Paper #2: Tom Jack (Nova Research and Technology Center)

- **Coatings and CP Compatibility**
- CP and Coatings. Must work together.
- A checklist was presented to aid in the definition of CP compatibility. Is it damaged by CP, allow CP to get to the pipe even when the coating fails, does not generate a damaging environment, will coating save the day without CP, and minimize the CP costs
- Examples: Use the checklist to answer the questions on that sheet.

- PVC tape wrapped coatings. Contains plasticizers and therefore fails over time as the plasticizer comes out. **NOT** CP Compatible.
- PE Tape. Shields the pipe from CP. **NOT** CP Compatible when failed.
- Asphalt Coating: Become permeable. Water and CP do get in. Promotes SCC environment. **NOT** CP Compatible.
- FBE: Under ideal conditions it is good. But with a defect you get cathodic disbondment. **Is pretty good** CP Compatible.
- New Coatings: Are these compatible, do we need CP?
  - FBE used in combination with tape wrap 2 meters away. FBE was good, tape had SCC and corrosion.

Discussion and Questions

- John Baron: How far under a disbondment can CP protect?
  - Not far, 10 to 15 cm but based on salinity of electrolyte. There are some exceptions due to geometry
- Jim Banic (SPC) – With respect to multi-layered coatings, if the substrate was coated no shielded was seen.
- Peter Singh (Shaw Pipe) – Do you need massive disbondment. Where does soil conductivity come into play?
  - A pipeline buried in rock had water soaking into the asphalt but due to the rock no CP could get to the pipe and corrosion occurred.
- Becky Morse – What is your experience with extruded PE?
  - It is pretty good. Not a lot of problems.
- Linda Gray - CP disbondment with FBE. Has there been active corrosion found under FBE with good CP?
  - Aida Lopez - Some, but very little.
  - Becky. You get breaks in the blisters and the low PH water gets out.
- Jamie (Dupont) yes there is some in the states.
  - Tom Webber – If the blisters are intact, there is no problem. This implies that if the blisters break your CP may not be good enough.
- John Baron – Over protection may have been a problem.
- Jim Banach (SPC) – It is still possible to get corrosion due to low current densities often used for cathodic protection of FBE coating pipelines.
- Jim Banach – Are there going to be changes to the testing with regards to coating disbondment? (i.e. longer CDs).
  - Merely extending current test duration is not seen as appropriate. New test methods are required.
- West Coast Energy. Pipe handling with respect to coatings (i.e. trucking). Is there anything within the new CSA with respect to this?
  - No specific changes.

Lunch Break

Paper #3: Becky Morse (Charter Coatings)

- **How We Perform Field Assessment of Coatings**
- Objective: Discuss the elements of field assessment of pipeline coatings.
- Two elements of Inpsection. Visual Inspection and Non-Destructive testing.

Visual Non-Destructive Assessment

- Girth Weld Coatings
  - Sleeves, Tape, and Other
- Types of Defects
  - Application problems, Environmental issues, blisters in Epoxy, clockspring compatibility

Destructive Testing

- Coating Integrity and Condition of the metal
- Field adhesion tests (X, triangle, peel)
- Holiday Testing (ASTM Test Method or Voltage0
- Cathodic Protection Compatibility
- Decision Path (Large or Small)
  - Short term moisture barrier
  - Long term mitigate corrosion
- Criteria for Repair
  - Compatible with existing coating
  - Compatible with operating temperature
  - Work for intended service

Discussion and Questions

- Tom Weber – Do you feel that field coatings require third party inspection?
  - Yes, coating in the field must be applied in the same way as in the plant.
- Phillip Nidd (Agra) – Do you have a data base with special problem relating to coatings
  - No but would consider being involved.
- Jim Banach (SPC) – What are the main causes of coating failure for shop and field?
  - Shop applied failures – 1) Coating used in the wrong application.
2) Operating conditions change.
  - Field applied failures – 1) Application!
- John Baron (Skystone Eng) – Holiday Testing, what is your recommendation for field holiday testing. Voltage?
  - Bob Bauer (TCPL) Low voltage (67.5V) wet sponge works well. Must educate the field personnel
- Mat Cetiner (Anteris Corrosion) – Should you include soil condition.
  - Yes
- Stan Wong (CC Tech) – Some of this information may already exist in the CEPA database.
- Glen Macintosh (Denso) – Absence of service history complicates coating assessments.
- Tom Weber - Look at current leakage testing procedure ASTM G18. It tests coating current leakage using a 6-volt cell tied to a specimen and measures the leakage.
- Phill Ned – One other factor is economics associated with coating application and cure time extending pipeline outage.

- Barry Martins (RPL) – Want to ensure coatings fail safe. We don't put rock shield on in rocky areas so that when it fails, CP gets in.

Paper #4: Peter Singh (Shaw Pipe Protection)

- **How We Select Coatings for High-Temperature Pipelines**
- Most applications are in heavy oil and conventional Oil and Gas
- Temperatures between 85 and 135 degrees C.
- Coatings used include tapes, FBE, multi-layers and liquid epoxies.
- Failure modes include embrittlement, cracking, disbondment, and mechanical damage from shear stresses.
- These coatings must do all normal coating requirements in addition to high temperature.
- Temperature effects include, lowered adhesion, reduced mechanical properties, increased permeation, increased corrosion rates and increased thermal stresses.
- Evaluation tools? There are currently no industry standards for assessment of high temperature coatings.
- Techniques used include cathodic disbondment, hot water adhesion, mechanical properties, glass temp, oxygen induction time
- Water adhesion at 95 degrees may not apply to service at higher temperatures.
- Cathodic disbondment increases with temperature and peaks around 80, less disbondment may occur at higher temperatures, 90-100C.
- Mechanical property tests do not indicate change in value with time dependence.
- Glass temperature (Tg) can be measured by DSC or DMA and is a reversible step change in properties, which limit the useful temperature.
- Higher Tg for multi-layered systems gives higher adhesion and peel strength.
- Oxygen induction time determines the antioxidants level in coating
- Accelerated heat aging. You age it at a higher temperature to accelerate the temperature effects and then extrapolate to determine coating life at lower temperatures.

Discussion and Questions

- Linda Gray (KTA Tator) Temperature 85 to 135 degrees C, is there liquid water in conduct with the line at those temperatures?
  - Often not since the heat tends to dry out the soil surrounding the pipe.
- Tom Weber (Trenton) Do you know if any tests can be made to predict high temperature effects?
  - There needs to be a number of tests to do this.
- Bob Smyth (Petroline) do you have experience around 300 degrees C
  - No
- Anteris Corrosion – In the CP disbondment graph presented, how many different types of coatings were used?
  - The idea wasn't to focus on the materials and the numbers, but rather on the trends; data is not specific, but more general in nature.
- Linda Gray – Indication tests are used how about Shore D Hardness. Is that a good method?
  - Yes, it is a good value. Indication is more time dependant.

- John Baron (Skystone) the Tg slide with multi-layered coatings. The "Primer" appears to have a large effect.
  - Yes
- Becky Morse (Charter Coatings) – The choice of primer is very important. Effects of long term CD and long term water adhesion testing.
  - CD has been run up to a year. 30-60 days is more typical. Solution has to be changed and therefore you require more in depth procedures.
- Jamie Cox (Dupont) is seeing pipelines around the world and was designed for around 110 degrees C using 3 layer polypropylene coatings.
  - Most qualified with CD tests around 100 C.
- John Baron (Skystone) Can you update us on CSA Z245.20/21 activity.
  - Discussion on 3 layered polypropylene standard, but has been on hold.
- Stan Wong (CC Tech) – Are there tests for high temperature coatings for areas around reciprocating equipment
  - Some
- Doug Waslen (NEB) Peter has looked at many tests; can you combine tests to gain more information?
  - Some of the testing is heading in that direction.
  - Jamie Cox (Dupont) – This is being done in some projects
  - John Baron (Skystone) – There needs to be more testing and standardization in this area. We have a lot of learning to do.

Paper #5: John Baron (Skystone Engineering)

- **How We Achieve Field-Applied Girth Weld Coating Quality**
- More emphasis on Field-applied coatings.
- Number of failures due to external corrosion has started to come down based on AEUB statistics.
- Coating performance testing will be included in the next CSA Z662
- Field applied coatings used on risers, repairs, welds etc.
- There are many different types of coatings to be used in these cases
- Problem usually due to bad design and application
- Shop + Field = Coating System. The system must be accurately designed
- For application most people use "Manufacturers recommendations"
- Application QA will be in CSA including procedures and personnel
- Industry needs increased standards to address field coatings until they reach a level close to shop applied quality.
- Shop applied coatings have good quality programs in place resulting in generally acceptable quality coatings.
- Field coatings also have to address insulated pipelines
- Coatings also have to deal with soil shear stresses not just peel and pull off adhesion.

Discussion and Questions

- Jamie Cox (Dupont) – Do you have shear stress numbers that are normal
  - 0.12 mPa is a normal resistance stress quoted in some European standards. This may be a little high. The trick is getting these values at the operating temperature required.
- Becky Morse (Charter Coatings) – Can you comment on specialty joint coatings for long bores
  - People are currently using a Fusion bond spec (CSA Z245.20) to apply liquid coatings. There needs to be a separate standard.
- Wayne Duncan (CSI Coatings) – How do you qualify people?
  - Usually a training seminar is put on by the manufacturer
  - Bob Bauer (TCPL) – Anyone touching the coatings is trained and will be tested.
- Mark William (Canusa) – It is the manufacturer who is doing the training. There is a large problem in many companies not asking for the training.
- John Morse (Charter Coatings) – Quality of sleeve application goes up with trained people and using the same trained people all of the time. Destructive testing could be used to keep the crew honest. Cut off a few sleeves with criteria of good and bad.
- Wayne Duncan (CSI) – You need more than a one day seminar. What is needed is quality procedures usually produce by the manufacturer. Possibly legislate that the people are trained and that the shop applied standards are met.
- John Baron (Skystone) – maybe you have to require more accountability by individual installers. For example, requiring putting the installers name on the joint. Gives some accountability.
- Mark William (Canusa) – Some companies have procedures that have destructive testing to prove quality. (i.e. cut off every 100th sleeve and test it)
- John Baron (Skystone) – Is this happening for liquid systems as well?
  - Wayne Duncan (CSI) – The do destructively test a percentage of the joints as required.
- Phillip Nidd (Agra) – His people go through a 3-day seminar. They also explain the results of bad coatings.
- Jim Banach (SPC) – Is it in CSA now to qualify personnel
  - Yes, personnel training is part of the new requirements.
- Bob Smyth (Petroline) – The inspectors should go through the same training. Often misinformed inspectors can create application problems by lack of knowledge of application procedures.

Paper #6: Aida Lopez (TransCanada Pipelines)

- **How We Select and Apply Repair and Rehabilitation Coatings**
- Two main repairs are large scale Rehab and then the small rehab during excavations.
- Large Scale Rehabilitation started in 1996. Currently use line travel equipment on areas over 5 km.
- Smaller sections, there are patch repairs, entire joint repairs.
- Depending on the coating uncovered and the length of damaged coating, different repair coatings are used.

- Depending on the pipeline operating temperature at that location, again different coatings are used.
- For cold temperature applications, the best coating are the Vinyl Esters and the Polyethylene
- Surface preparation is critical. Usually near white blast.
- For yellow jacket girth welds, they use liquid epoxy with the ends wrapped with a sealant.

Discussion and Questions

- Jim Banach (SPC) – Liquid epoxies with yellow jacket. The PE needs more treatment, has TCPL looked into this.
  - Bob Bauer – Treating the PE with Fluorine gas does help a small amount. Although, due to safety this is not practical solution.
- Are there any safety problems with asphalt coatings?
  - Yes, asbestos in the coating is a problem. People wear the appropriate safety clothing, wet blasting techniques used to eliminate dusting.
- Peter Singh (Shaw Pipe) – The flame oxidation of the PE can be completed to help the bond although the spec is very specific.
- Jim Banach (SPC) – Flame treatment helps but there are others such as chemical treatment that may be more effective.
- Phillip Nidd (Agra) – The 2 layered epoxy continuous to cure after burial. Have you seen problems due to backfilling before coating is cured?
  - Backfilling should not occur if the coating isn't properly cured in accordance with TCPL specification for hardness.

Conclusions and Recommendations – Working Group 6

Proposed Changes to CSA Codes

- The new changes will help define the coating selection, application and quality processes.
- The challenge will be to implement the new requirements.
- The CSA Z662 Commentary document currently being prepared should include information on these new requirements such as the flow chart from the presentation and background information.

Coatings and CP Compatibility

- The definition of CP compatibility is not clearly understood.
- The proposed definition will provide a basis to assess coatings.
- It appears that not all coatings will meet the definition discussed.
- The CSA Z662 Commentary document currently being prepared should include information on the definition of CP compatibility.

How We Perform Field Assessment of Coatings

- You need to perform visual and destructive testing to assess coating condition.
- Operators should take the opportunity during excavations to assess and document the coating condition.
- A database to capture this information would be a benefit to industry.
- A simple checklist was presented which could facilitate the gathering of coating assessment information.

How We Select Coatings for High-Temperature Pipelines

- No industry testing standards exist specific to high temperature coating qualification (>85C).
- High temperature coatings have been used based on individual company specifications.
- CSA coating standards should address high temperature coating requirements.
- High temperature assessments will likely require accelerated heat aging methods.

How We Achieve Field-Applied Girth Weld Coating Quality

- The new CSA revisions, which include selection and application requirements for field, applied coatings, will require more up-front design.
- The industry requires a frame work for applicator qualification (including training, documentation and quality assurance)
- The compatibility of the field applied coating with the shop applied coating must be assessed.

How We Select and Apply Repair and Rehabilitation Coatings

- Coating selection for repairs and rehabilitation are dependant on the various factors such as pipe temperature and existing coating specific to a location.
- Often a combination of coatings is often required to achieve compatible system.
- Each repair method has documented procedures for application and training.

General Conclusion and Recommendations

- A coatings discussion group should be established to enable regular and ongoing improvements.
- It appears that coating selection, application and quality controls are improving.
- Coating technologies are continuously improving to meet the needs of industry.

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Proposed Changes to CSA
- Coating Assessment -

Working Group 6 - Coatings
Doug Waslen

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CSA Changes - driver

- Recommendation from NEB SCC Inquiry Report 1996
  - Develop standard tests where none currently exist that determine whether a coating will meet the requirements of Z662 (9.2.7.1) over the anticipated service life of the pipeline.
  - Incorporate those tests in the appropriate CSA standard

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CSA - action

- Formed a work team in November 1998
- 23 member team
- Chaired by Doug Waslen

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Work Team - direction

- Challenge was to decide whether or not available tests (CSA, ASTM) determine performance over the service life
- Testing combined with in-service performance is ideal
- Testing alone makes assumptions and is open to interpretation
- Reduce variables (address application and quality issues)

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Work Team - results

- Focussed on 5 areas
  - assess coating for suitability
  - test the coating
  - application and quality assurance procedures
  - reassess coatings for changes in formulation, manufacture or change in manufacture
  - reassess coating(s) for changes in service (temperature, etc.)

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Coating Suitability Assessment

- Pipeline design
- Construction
- Operation
- Coating application
- Service changes over the pipeline life
- Interaction with dissimilar coatings
- Duration and method of coated pipe storage

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Coating Testing

- Properties listed in 9.2.7.1
  - isolation from the environment
  - adhesion
  - ductile
  - strength and adhesion
  - resist degradation
  - compatible with CP
- Tests listed in Appendix L

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Application Procedure

- Shop and field applied coatings shall have documented procedures and suitable quality programs
- Procedures shall include:
  - QA tests for coating and abrasive
  - personnel qualifications
  - application requirements

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Reassessment Requirements

- Changes in service, change in temperature etc
- Coating formulation, change in manufacture, change in location of manufacture

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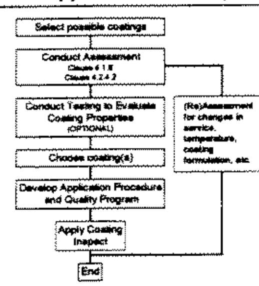
Coating Selection, Assessment, Application and Inspection



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Field Assessment of Pipeline Coatings

Becky Morse
Charter Coating Service Ltd.

Charter Coating SERVICE LTD.

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Objective

To discuss the elements of field assessment of pipeline coatings.

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"Consequences"

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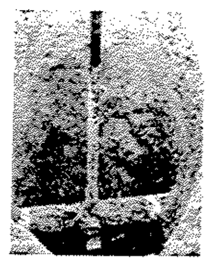
Visual Inspection



Identify the coating type

- Tar & Wrap
- Coal Tar Enamel & Bitumastic
- Tape
- Extruded PE
- FBE
- Other

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Non-Destructive Assessment

Mainline Coating

- Age
- Operating conditions
- Previous failures

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Non-Destructive Assessment

Girth Weld Coatings

- Sleeves
- Tape
- Other

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Non-Destructive Assessment

Type of Defects

- Application
- Environmental

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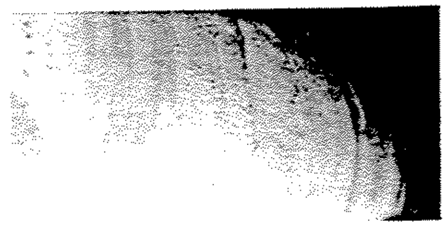
Blisters in Epoxy



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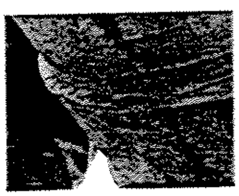
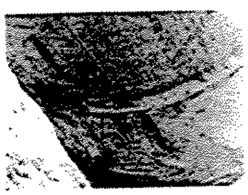
Other Coating Issues
Coated ClockSpring Repair





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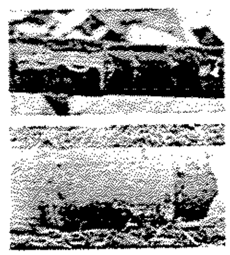
Destructive Tests



- Coating Integrity
- Condition of Metal

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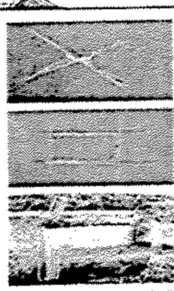
Field Adhesion Test



- 'X' Cut
- Rectangle Cut
- Peel Adhesion

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Rating Scales for Adhesion

'X-Cut'	NACE 'Rectangle Cut'*
A=no substrate visible.	1=coating cannot be removed cleanly.
B=less than 50% of area shows substrate.	2=less than 50% can be removed.
C=more than 50% of area shows substrate.	3=50% or more can be removed.
D=no coating remaining within 'X-Cut'	4=coating removed easily in large pieces.
E=coating removal beyond the area of 'X-Cut'.	5=coating completely removed in one piece.

*CAN/CSA-Z245.20-98

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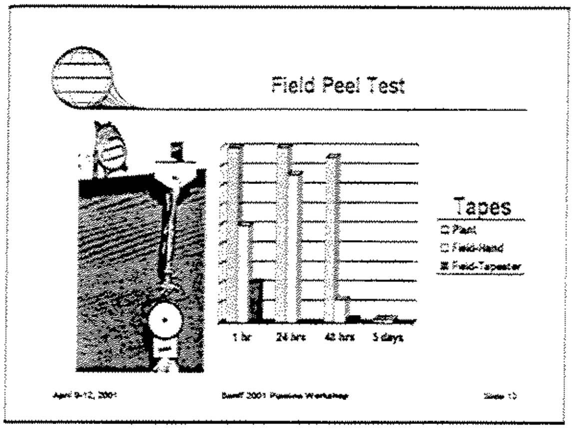
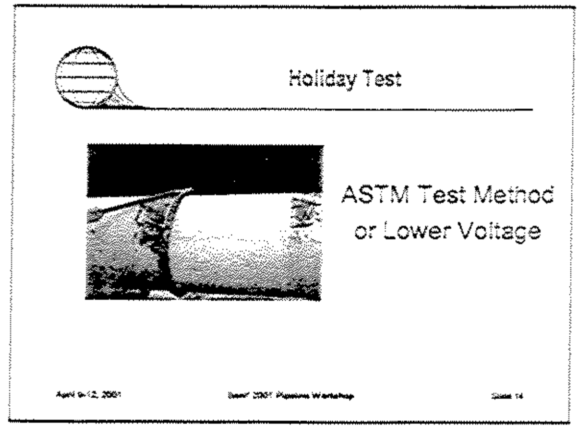
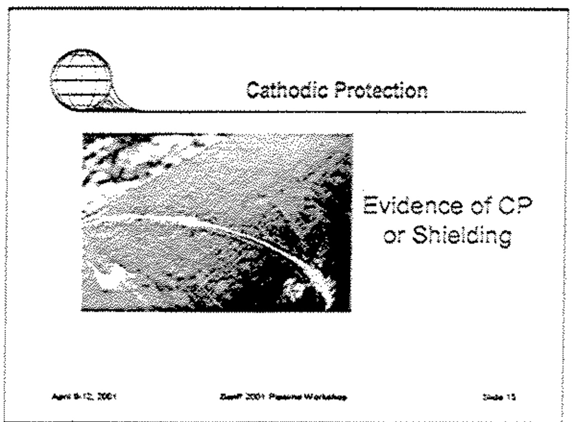
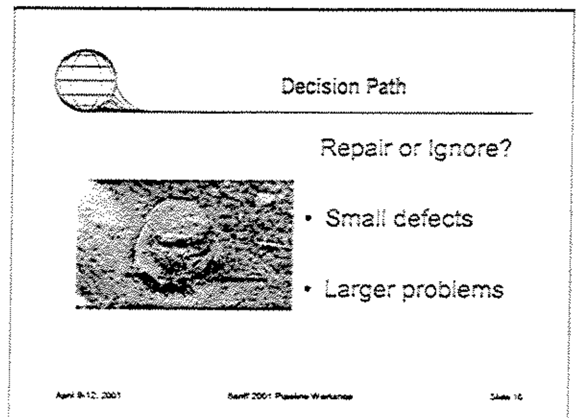
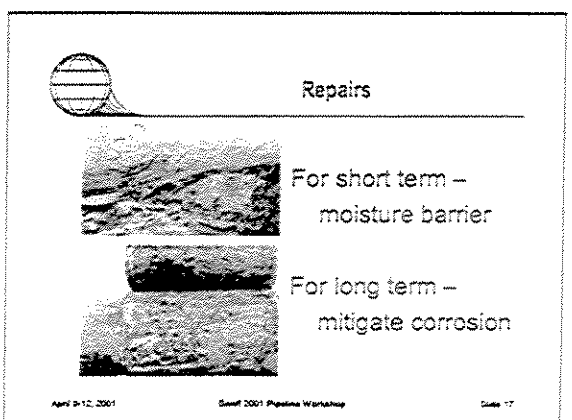
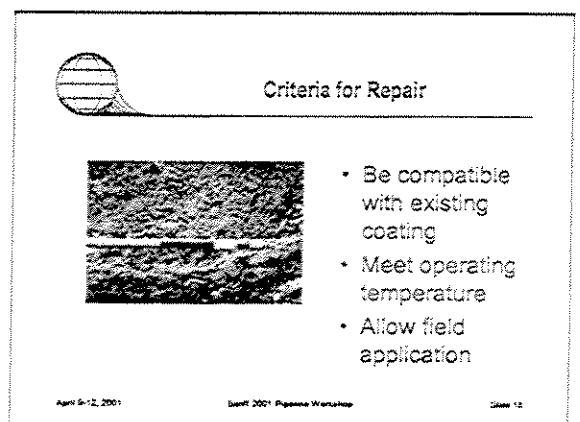

Field Peel Test
Tapes
Plant
Field-Hand
Field-Tapester
1 hr
24 hrs
48 hrs
5 days

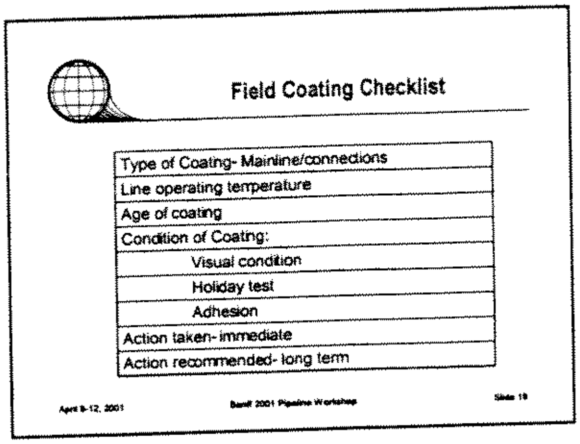

Holiday Test
ASTM Test Method
or Lower Voltage


Cathodic Protection
Evidence of CP
or Shielding


Decision Path
Repair or Ignore?
• Small defects
• Larger problems


Repairs
For short term –
moisture barrier
For long term –
mitigate corrosion


Criteria for Repair
• Be compatible with existing coating
• Meet operating temperature
• Allow field application


Field Coating Checklist
Type of Coating- Mainline/connections
Line operating temperature
Age of coating
Condition of Coating:
Visual condition
Holiday test
Adhesion
Action taken- immediate
Action recommended- long term
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Coatings and CP Compatibility
Tom Jack
NRTC

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The Basic Problem

Iron is an abundant, inexpensive metal used in the fabrication of much of our infrastructure including pipelines.

Unfortunately it is also

- *Thermodynamically unstable in most operating environments ⇒ Corrosion.*
- *Subject to a degradation of its mechanical properties in some environments ⇒ Cracking.*

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The Protection of Iron (0)

In pipeline applications, iron is maintained in its original form by a combination of

- Cathodic protection (CP)
- Protective Coatings

These systems must work together for the life of the facility in all foreseeable circumstances

- CP must not damage the coating in a way that exposes unprotected metal to a damaging environment
- The coating must not allow a damaging environment to contact the metal surface

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A Mission Statement for Coatings!

A coating must prevent a damaging environment from contacting the pipe surface under all foreseeable circumstances over the life of a facility in a given operating environment.

Any deviation from this expectation is a coating failure.

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CP Compatability - A Check List

A CP Compatible coating is one that

- is not damaged by CP in a way that leads to coating failure
- allows CP to protect the pipe from corrosion even when damaged, defective or degraded in service
- does not generate a damaging environment at the pipe surface as a result of interactions with CP
- provides value by
  - minimizing the cost of CP installations and operations
  - providing stand alone protection when necessary under all circumstances

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CP Compatability Check List

	PVC tape	PE tape	Asphalt	FBE	New
CP promotes coating failure?					
CP protects pipe despite coating defects, degradation, damage?					
Harmful environment forms at pipe surface through action of CP?					
Loss of CP never matters - the coating will always save the day?					
Coating always keeps cost of CP low?					

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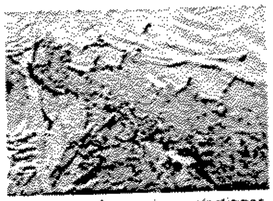
Could a Really Bad Coating be CP Compatible?



PVC Tape Coating loses plasticizer

- Some historical coatings proved very susceptible to degradation in service
  - e.g.'s wax, PVC Tape…
- If a coating degraded locally…

Would it be CP Compatible?

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Are PE Tape Wrap Coatings CP Compatible?

- Polyethylene tape is inert to material degradation underground BUT can disbond to allow the groundwater environment to reach the pipe surface
- Usually, the environment next to the pipe is
  - Shielded from CP
  - Remains near pH 7
    - corrosion (MIC)
    - Near Neutral pH SCC

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Is Asphalt a CP Compatible Coating?

- Asphalt can become permeable over time in service allowing water and CP to reach the underlying pipe
  - Electrochemical reactions on the steel surface build up a concentrated basic solution of $NaCO_3/NaHCO_3$
- The pH and potential are too "high" to allow classical SCC or corrosion

IS THIS A CP COMPATIBLE COATING?

WHAT IF THE CP IS LOST?

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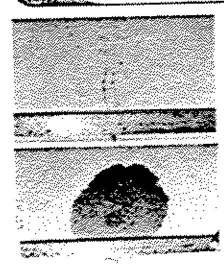
Is FBE CP Compatible?



- Under ideal circumstances, FBE performs well with slight CP current after years of service.
- But blisters are seen in the field
  - high pH solution is formed next to the pipe
    - no corrosion? no cracking?
    - disbondments are limited in size

Is this a CP compatible coating?

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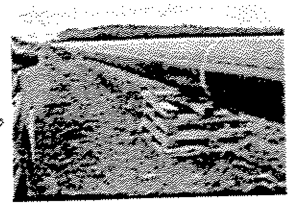
What about New High Integrity Coatings?

- Examples include multiple layer coatings, e.g.
  - a tough outer coating for mechanical protection
  - a pipe surface coating with excellent adhesion

Are these CP compatible?

What could possibly go wrong?

Do we even need CP?



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Answers to the Test Questions

TEST CASE	FIELD EXPERIENCE
• A really degraded coating – e.g. PVC Tape	⇒ Horrendous corrosion problems ⇒ *partial shielding* ⇒ *problem with getting CP up?*
• Disbonded "intact" PE Tape	⇒ "Classic" shielding disbondment ⇒ *corrosion, neutral pH SCC*
• Permeable asphalt	⇒ Has anyone seen high pH SCC? ⇒ Shielded areas show corrosion and neutral pH SCC
• FBE - occasional blisters	⇒ Not known for corrosion or SCC
• New High Integrity Coatings	⇒ Will be "perfect", of course

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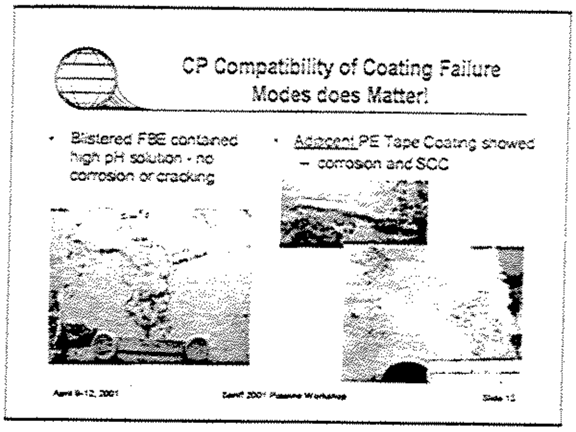
CP Compatibility of Coating Failure Modes does Matter!
• Blistered FBE contained high pH solution - no corrosion or cracking
• Adjacent PE Tape Coating showed
– corrosion and SCC

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Assessment of Coatings for High Temperature Pipelines

Peter Singh, Shaw Pipe Protection

BREDERO-SHAW

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BACKGROUND

- HEAVY OIL
  - production using steam assist
  - transportation at high temperature
- CONVENTIONAL OIL/GAS
  - deep wells
  - temperature maintained to prevent hydrates formation and wax deposition
- TEMPERATURE
  - >85C and up to 135C

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EXPERIENCE

- COATINGS
  - tapes, FBE, multi-layers, liquids
- FAILURE MODES
  - embrittlement and cracking
  - disbondment
  - mechanical damage from shear stresses

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COATING REQUIREMENTS

- COATING MUST PERFORM ADEQUATELY:
  - at normal construction conditions
  - and startup/shutdown
- IN ADDITION TO
  - high temperature operation

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TEMPERATURE EFFECTS

- Deterioration of mechanical properties
- Lower adhesion
- Thermal degradation
- Increased permeation
- Increased corrosion rates
- Increased thermal stresses

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EVALUATION TOOLS

- No standards exists for high temperature coatings
- A variety of test methods and acceptance criteria are used to evaluate high temperature coatings
  - specific method depends on coating type

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TECHNIQUES

- Cathodic disbondment
- Hot water adhesion
- Mechanical properties at temperature
  - adhesion, indentation, tensile
- Glass transition temperature Tg
- Oxygen induction time OIT
- Accelerated heat aging

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CD/Hot Water Adhesion

- Modified ASTM G8/G42, CSA Z245.20
  - temperature and time
- Limited to ~ 95C
- Does not indicate performance at higher temperatures
- Good for comparison of coatings

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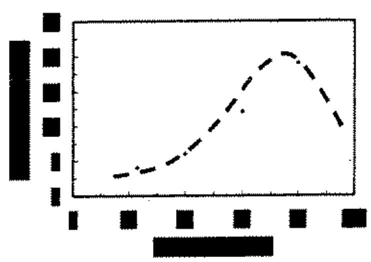
CATHODIC DISBONDMENT



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MECHANICAL PROPERTIES

- Properties include:
  - adhesion, indentation, tensile, etc.
- Measurement of property at temperature
- Does not indicate change in value with time at temperature

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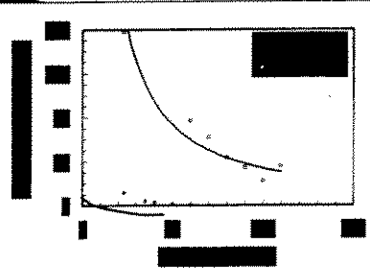
PEEL ADHESION



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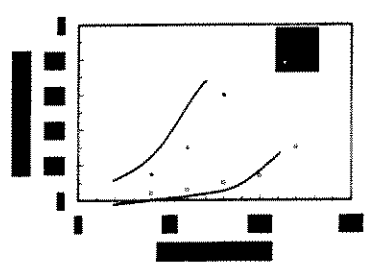
INDENTATION



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Tg

- Measured by DSC, DMA
- Fundamental polymer property
  - reversible step change in properties beyond Tg
- indicate limiting temperature due to property changes
- Does not indicate thermal degradation

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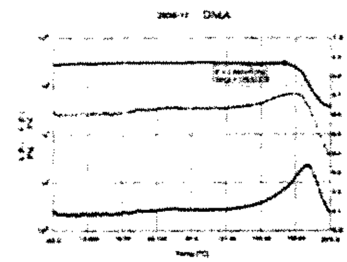
Dynamic Mechanical Analysis
POLYURETHANE



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Tg

- Coatings with primer coat having a higher Tg display:
  - higher adhesion and peel strength
  - lower cathodic disbondment
  - higher retention of adhesion after immersion in hot water

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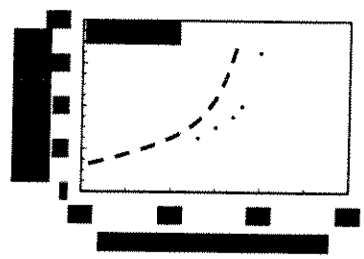
PEEL ADHESION



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OIT

- Determination of antioxidant level in coating
- Auto-oxidation is principal method of degradation of polymers in high temperature
- Modification of CSA Z245.21 OIT method

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ACCELERATED HEAT AGING

- Aging at temperatures above design to accelerate effects
- Measurement of properties
- Extrapolation of results to determine property or lifetime at design temperature
- Good scientific tool
- Must be tailored to specific situation

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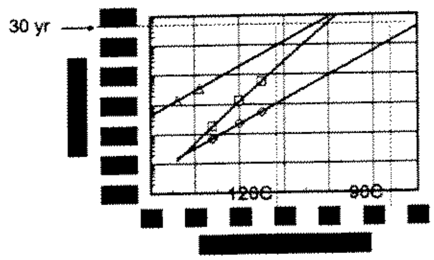
LIFETIME PREDICTION



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CONCLUSION

- No standard exists for assessment of coatings for high temperature service
- Various test methods with acceptance criteria being used
- Validation of assessment methods needed

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Quality Field Joint Coatings
Moving from Afterthought to Priority
John Baron
Skystone Engineering Inc.

April 9-12, 2001 Banff 2001 Pipeline Workshop Skystone Engineering Inc.

Coating BACKGROUND -Pipeline

- Increased awareness of external corrosion owners, regulators
- 1/3 of Pipeline failures due to external corrosion
- CSA Z662, will include of coating testing to ensure performance criteria met. (Clause 9.2.8.1)

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BACKGROUND

- Field-applied, primarily to girth welds, repairs, risers, etc.
- covers the shop-applied coatings cut-back length plus weld.
- usually applied by construction contractor or sub-contractor
- coating materials normally specified by the end-user, based on experience,etc

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OBSERVATIONS

- External corrosion at girth welds is a significant concern
- Problem often caused by poor design and/or field-application quality

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DESIGN

- CSA will require an assessment of shop and field applied coatings!!
- Shop-ctg + FJC = Ctg System
- FJC's often evaluated independantly

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APPLICATION

- Application standards generally based on "manufacturer's recommendations"
- most pipeline companies have in-house standards for application
- personnel training & material qualification normally specified!!
- code requirements for application quality are coming in CSA Z662!!

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Installation Specification

- Steel preparation cleaning, drying, pre-heat, weld splatter grinding, weld bead condition
- Materials and application equipment
- Application procedure
- Qualification of materials and personnel
- Quality verification

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What's Needed??

- Industry Design standards to address FJC's
- Specifically:
  - alignment with shop-applied coatings design performance criteria
  - shop-applied coatings/interface performance
  - CP compatibility
  - application quality - personnel, QA tests

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FJC's- "The future?"

- Increased specialist vendors to supply and apply FJC's.
- FJC quality will match or be very close to shop-applied coating quality.
- Codes will require materials qualification and applied quality performance.
- FJC materials will further evolve to match shop-applied coatings evolution

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Challenge for the Next Millennium

"To select and apply pipeline coatings, in a manner, which significantly lowers probability of external corrosion occurring over the life of the pipeline"

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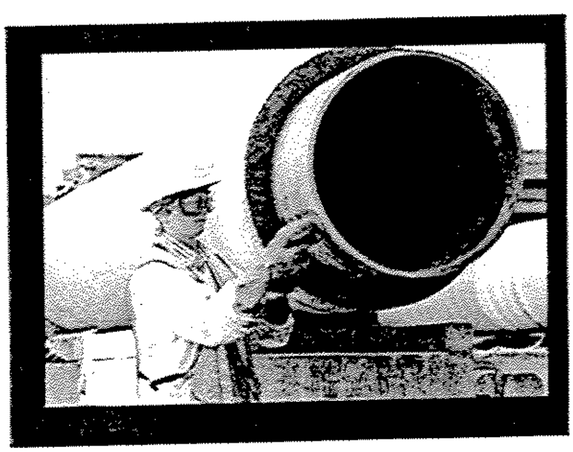

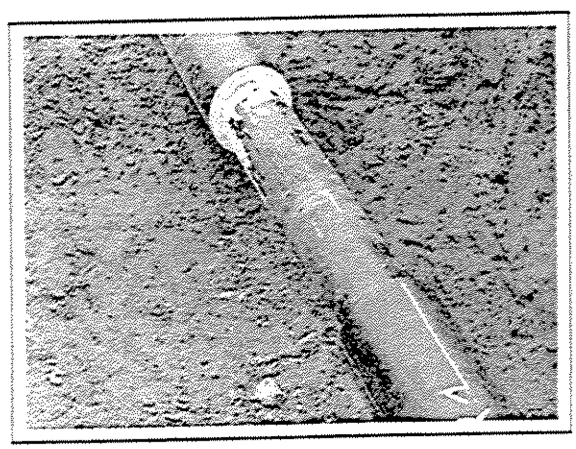

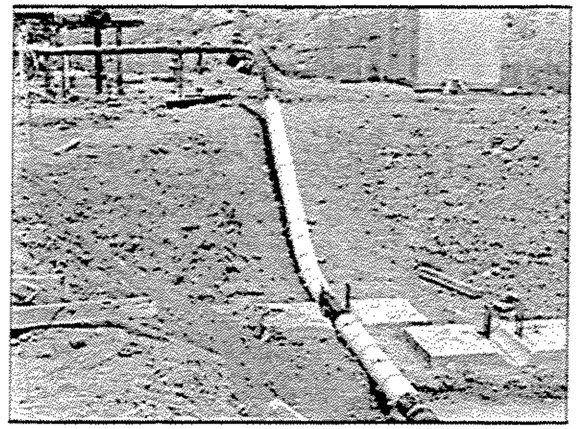

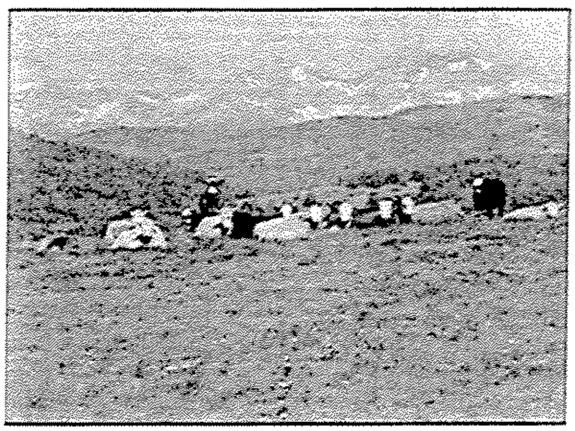

BANFF/2001
PIPELINE WORKSHOP

Repair and Rehabilitation Pipeline Coatings

Aida Lopez - Bob Bauer - Kevin Orthner
TransCanada Pipelines

April 9-12, 2001 Banff 2001 Pipeline Workshop TransCanada

PIPELINE SYSTEM INFRASTRUCTURE

- 36,000 km of System - Wide Transmission Pipelines
  - 15,000 km of Transmission Pipelines (Mainline)
  - 21,000 km of Transmission Pipelines (Alberta)

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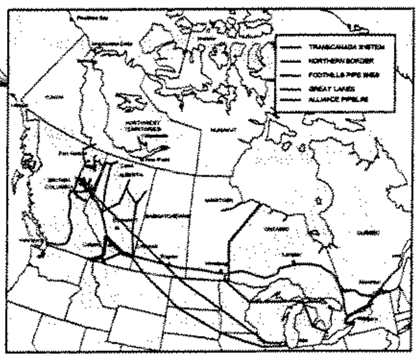

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COATING SYSTEMS

- Existing Coatings
  - Asphalt
  - Coal Tar
  - Tape
  - FBE
  - Extruded Polyethylene
  - Urethane
- New Coatings
  - FBE
  - Liquid Epoxies
  - Extruded Polyethylene
  - Urethane
  - Vinyl Esters

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Deteriorated Coatings

- Tape

- Asphalt

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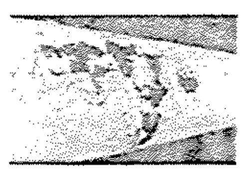
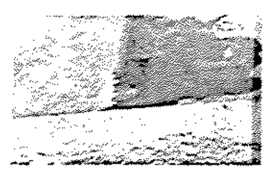
Deteriorated Coatings

- FBE



- FBE & Urethane



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Repair and Rehabilitation Procedures

- Large Scale Rehab (> 5km)
- Smaller Scale Rehab:
  - PMP Digs
  - SCC Digs
  - Construction Exposure
  - Investigative Digs

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Large Scale Rehabilitation

- Since 1996 over 80 Km (50 miles) of Transmission Pipe has been Recoated using:
  - Line Travel Equipment
  - Liquid Epoxies
  - Length >5km

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Smaller Scale Program

- Existing Coating in Good Shape but Requires a Patch Repair
- Existing Coating Badly Deteriorated
- Repairs when Pipe Surface Temperature is > 10°C
- Repairs when Pipe Surface is <10°C

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Existing Coating in Good Shape but Requires a Patch Repair

- FBE and Liquid Epoxies:
  - Liquid Epoxies
  - Sweep-Blast Existing Coating (4-10cm)
- Asphalt-Coal Tar-Tapes-Extruded Poly:
  - Moldable Sealant with Bonded Polyethylene Outerwrap
  - Sweep-Blast Existing Coating (4-10cm)

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Existing Coating Badly Deteriorated

- FBE and Liquid Epoxies:
  - Liquid Epoxies
  - Sweep-Blast existing Coating (4-10cm)
- Asphalt-Coal Tar-Tapes-Extruded Polyethylene:
  - Liquid Epoxies
  - Extruded Polyethylene
  - Shrink Sleeves
  - Petrolatum & Fiberglass Outerwrap
  - Moldable Sealant with Bonded Polyethylene Outerwrap

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Repairs When Pipe Surface Temperature is > 10°C

- Liquid Epoxies (Mainline & Alberta)
- Extruded Polyethylene (Alberta)
- Tie-ins:
  - Liquid Epoxies (for FBE, Epoxies, Urethanes Coated Lines)
  - Shrink Sleeves (for Extruded Polyethylene Coated Lines)
  - Petrolatum & Fiberglass Outerwrap or Moldable Sealant with Bonded Polyethylene Outerwrap (for Tape, Extruded Polyethylene,Asphalt and Coat Tar)

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Repairs When Pipe Surface is <10°C

- Epoxy is the Priority Coating but it has Limited Applications when Pipe Surface Temperature is Below 5 °C
- Acceptable Mixing and Application at Ambient Temperatures as low as -20 °C
- Vinyl Ester (Surface Temp -2 to 0 °C)
- Urethanes (Surface Temp. 0-5 °C only for Cases where Abrasion is an issue)

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RESULTS

- All these Coatings Have Been Successfully Qualified for Their Applications (Tested in the Lab and Field)
- Cure Complete Usually Under 4 Hours
- SSPC SP-10 Surface Preparation (2mils anchor)

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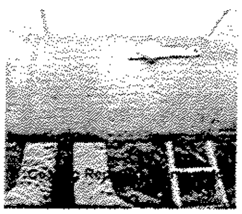
Coating Repair of a Girth Weld on Extruded Polyethylene Coated Pipe

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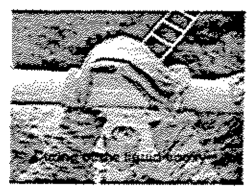
Coating Repair of a Girth Weld on Extruded Polyethylene Coated Pipe

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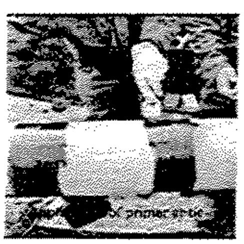
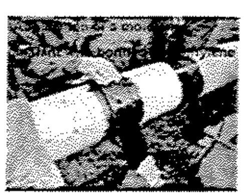
Coating Repair of a Girth Weld on Extruded Polyethylene Coated Pipe

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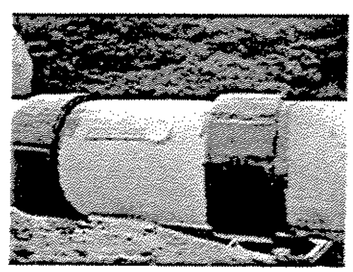
Coating Repair of a Girth Weld on Extruded Polyethylene Coated Pipe



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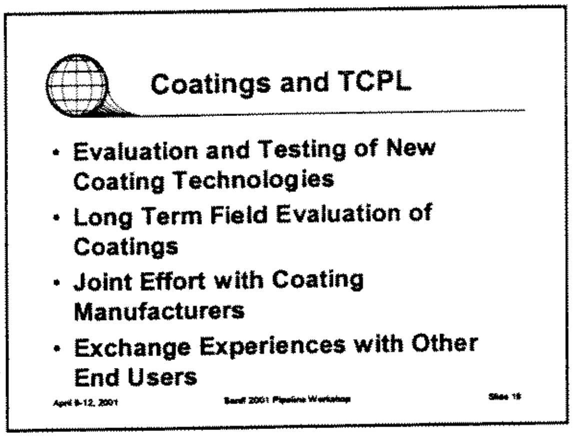
Coatings and TCPL
• Evaluation and Testing of New Coating Technologies
• Long Term Field Evaluation of Coatings
• Joint Effort with Coating Manufacturers
• Exchange Experiences with Other End Users

Managing Pipeline Integrity: Coatings (including Repair and Requirements of Z662/Z245.20/21) Banff/2001 Pipeline Workshop
April 11, 2001 10:30 a.m. - 12:00 p.m.

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2	HEMPEL COATINGS	JACQUES EBERLE	(604) 273-3200	sales-ca@hempel.com	
3	WEST COAST ENERGY MAYNARD BERGH	MAYNARD BERGH.	250-233-6341.	MBERGH@WEI.ORG.	
4	ALLIANCE PIPELINE	ROB POWER	403-517-7740	rob.power@alliance-pipeline.com	
5	Colt Engineering	Howard Wallace	403-259-1811	hwallace@coltvision.com	
6	Greenpine Industries	Layton Beatty	403-260-6730	laytonbeatty@greenpine.com	
7	NEB	Ken Yip	(403) 299 3195	kyip@neb.gc.ca	
8	GLOBAL THERMOELECTRIC	CORAL LUKANIUK	403 204-6174	lukaniukc@globaltc.com	
9	NEB	Rima Raad	(403) 299-3624	rraad@neb.gc.ca	
10	Husky Oil	Scott Arndt	(780) 871-6553	Scott.Arndt@husky-oil.com	
11	KTA-Tator (Canada)	LINDA GRAY	780-440-9391	Lgray@kta.com	
12	BCGAS	BRUNO ORLICZEK	250 862-6525	borliczek@bcgas.com	
13	BC GAS	FRED BARNES	604 592 7698	fbarnes@bcgas.com	
14	BC Gas	Chris Junger	250-868-4571	cjunger@bcgas.com	
15	Charter Coating	Amal Al-Borno	(403) 250-3027	aalborno@chartercoating.com	
16		CINDY SMALLMAN	(403) 202 0548	CSMALLMAN@HOME.COM	
17	KOCH PIPELINES CDN.	Neil S. Hay	(403) 716-7670	HAYN@KOCHIND.COM	

Managing Pipeline Integrity: Coatings (including Repair and Requirements of Z662/Z245.20/21) Banff/2001 Pipeline Workshop
April 11, 2001 10:30 a.m. - 12:00 p.m.

	COMPANY	NAME	PHONE	E-MAIL	SIGNATURE
18	EXXONMOBIL CANADA	PETER MARRECK	(403) 260-7795	PETER.M.MARRECK@EXXONMOBIL.COM	
19	Flint Field Services Ltd.	Don Ulsifer	(403) 342-8066	dulsifer@flint-energy.com	
20	DENSO NORTH AMERICA INC	GLENN MACINTOSH	780.910.1717	glenn@densona.com	
21	Canusa-CPS	Mark William	403-218-8207	Mark.William@shawlind.com	
22	CSI COATING SYSTEMS INC	WAYNE DUNCAN.	780-955-2856	wduncan@csicoating.com	
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25	National Energy Board	Nancy Dubois	(403) 299-3101	ndubois@neb.gc.ca	
26	BOND COATING SERVICES	CLIFF MITCHELL	(403) 279-7118	cjmitch@telusplanet.net	
27	DuPont Canada Inc	Jamie Cox	403-254-6145	Jamie.Cox@can.dupont.com	
28	Shaw Pipe Protection Ltd	Peter Singh	403 218 8229	peter.singh@bredero.com	
29	CHARTER COATING SERVICE	BECKY MORSE	403-250-3027	bmorse@chartercoating.com	
30	TRENTON CORP.	TOM WEBER	281-556-1000	TRENTONHOU@AOL.COM	
31	CORRPRO CANADA, INC	GRANT FIRTH	(780) 447-4565	grant.firth@corrpro.ca	
32	Imperial Oil Pipelines	Lorna Harron	(780)-955-6177	lorna.harron@esso.com	
33	SPECIALTY POLYMER COATINGS	JIM BANACH	(403) 870-6233	jim@spc-net.com	
34	SUN-CANADIAN PIPELINE	IAN SMITH	905 689 6641	ismith@sun-canadian.com	

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42	Atco Pipelines	Ben Sokol	780 420-7581	ben.sokol@atcopipelines.com	[illegible]
43	CC Technologies	Stan Wong	403-295-6080	wongst@cadvision.com	[illegible]
44	CANMET MTL	Winston Revie	613-992-1703	wrevie@nrcan.gc.ca	[illegible]
45	PII North America Inc	Bruce Hagerman	713-849-6332	hagermanb@PII-USA.com	[illegible]
46	CORROSION SERVICE	TREVOR PLACE	403-233-2601	tplace@corrosionservice.com	[illegible]
47	CANSPEC GROUP INC.	DAVID JOLIVETTE	780-490-2550	djolivette@canspec.com	[illegible]
48	Pacific Northern Gas	John Craig	604-691-5857	jcraig@wei.org	[illegible]
49	Charter Coating	John Morse	403 250 3027	Jmorse@chartercoating.ca	[illegible]
50	Westcoast Energy	Jennifer Wong	604-691-5973	JJwong@wei.org	Jennifer Wong
51	Alliance Pipeline	Terri Johnston	403 517 7701	johnstt@alliance-pipeline.com	[illegible]

Managing Pipeline Integrity: Coatings (including Repair and Requirements of Z662/Z245.20/21) Banff/2001 Pipeline Workshop
April 11, 2001 10:30 a.m. - 12:00 p.m.

52	Anteris Corrosion	Matt Cetin	403 232 8212	cetinez@home.com	403-232 8212
53	MARR ASSOCIATES	MARK JOHNSON	403-258-2233	mjohnson@marr-associates.com	[illegible]
54	Corrosion Service Comp	Alex Petrusev	403-253-2601	apetrusev@corrosionservice.com	[illegible]
55	SOLOMON COATINGS LTD	THOMAS WRIGHT	7804134545	THOMAS@SOLOMONCOATINGS.COM	[illegible]
56	PETROLINE	Bob Smyth	403 271-8383	RSMYTH@PETROLINE.COM	[illegible]
57	GREENPIPE INDUSTRIES ~~[illegible]~~	ANNA MORBACHER	403-260-6746	morbacher@greenpipe.com	[illegible]
58	WINTECH INSPECTION	MARTIN WINSPEAR	780 907 5005	wintech@attglobal.net	[illegible]
59	AGRA PIPELINE PROFESSIONALS	PHIL NIDD	713 562 3702	pgnidd@attglobal.net	[illegible]
60	HUNTER McDONNELL PIPELINE SERVICES	DEBBIE SIEMENS	780 913-4677	deb@hmpsi.com	D.S.
61	RTD QUALITY SERVICES	ANDRÉ FILIATRAULT	(780) 440-6600	afiliatrault@rtdquality.com	[illegible]
62	RTD QUALITY SERVICES	BOB SIMMONS	(780) 468-3619	bsimmons@rtdquality.com	[illegible]
63	~~[illegible]~~ IPSCO INC	Tom Lawrence	306-924-7395	tlawrence@ipsco.com	[illegible]
64	Conoco Inc.	Jill Hopkins	(307) 382-4514	jill.m.hopkins@usa.conoco.com	[illegible]
65	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
66	Trans Mountain PipeLine	Shawn McGregor	250 371-4011	Shawnm@TMPL.CA	[illegible]
67	"	Mark Otten	250 371-4030	marko@tmpl.ca	MO
68	NEB	Ken Yip	(403) 299-3195	kyip@neb.gc.ca	[illegible]

69	KOCH PIPELINES CANADA	MARTY WELDON	(403) 716-7586	weldenm@kochind.com	[signature]
70	BC GAS	BARRY ANDERSON	(250) 868-4572	bwanderson@bcgas.com	[signature]
71	Rainbow Pipe Line	Barry Martens	780 449 5856	barry_j_martens@email.mobil.com	[signature]
72	SUNCOR ENERGY MARKETING	BRIAN DENNIS	780 449 2108	BDENNIS @ SUNCOR . COM	[signature]
73	RAE INSPECTION SERVICE	Ramesh Singh	780-469-2401	ramesh@raeinspection.com	[signature]
74	CORRPRO CANADA INC.	Zane Reinhart	403-235-6400	Zane.Reinhart@corrpro.ca	[signature]
75	Rainbow Pipe Line	David Feser	403 260 7338	david_a_feser@email.mobil.com	[signature]
76	NOVA Research	Fraser King	[illegible] 4714	[illegible]	
77	CORRENG CONSULTING SERVICE INC	Bob Gummow	416-630-2600	bgummow@correng.com	
78	CATHOLIC UNIVERSITY OF RIO DE JANEIRO	IVANI BOTT	55(21) 5400703	bott@mail.rdc.puc-rio.br	[signature]
79	Trans Mountain P/L	Greg Toth	604-739-5324	gregt@tmpl.ca	[signature]
80	[illegible] Canada	Bruce Moore	(306) 536-7520	bruce.l.moore@[illegible].com	[signature]
81	TRANS MOUNTAIN P/L	MIKE REED	604 739-5367	MIKERE@TMPL.CA	[signature]
82	ATCO Pipelines	Art Janz	(780) 420-7536	art.janz@atcopipelines.com	[signature]
83	LANCE BENGERT	LANCE BENGERT	250-960-2006	lbengert@wei.org	[signature]
84	Foothills Pipe Lines	Kyle Keith	403 294 4446	kyle.keith@foothillspipe.com	[signature]
85	CDT Engineering	ART HARMS	403 259 [illegible]	harms.art@[illegible].com	[signature]

86	Trans Mountain Pipe Line	Kyla Loewen	780-449-5913	Kylal@tmpl.ca	
87	Pierce Consulting Ltd	Chris Pierce	403-281-8627	cpierce@telusplanet.net	
88	Nova Chemicals	Mary Gale	403 314-7491	galem@novachem.com	
89	Ray Smith	Pipeline Consultant	(403) 241-1680	raysmith15@home.com	
90	DOUG WASLEN	NEB	403-299 3680	dwaslen@neb.gc.ca	
91	John Barron	Skystone Eng Inc	403 216 3485	jbarron@skystone.ca	
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BANFF/2001
PIPELINE WORKSHOP

Group #6 : Coatings Workshop Summary
Co-Chairs : John Baron (Skystone Engineering)
Doug Waslen (National Energy Board)
Rapporteur: Kelly Mabbott (Skystone Engineering)

April 9-12, 2001 Banff 2001 Pipeline Workshop

Coatings Workshop Summary

- Paper #1: Proposed Changes to CSA Codes
  - Next edition to CSA Z662 is expected in 2002
  - Concerns were raised with the process of coatings design
  - Recommendation to include workshop information in the CSA Commentary
- Paper #2: Coatings and CP Compatibility
  - Definition and common understanding of CP Compatibility is required
  - A definition and checklist to assess coatings was presented
  - Recommendation to include workshop information in the CSA Commentary

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Coatings Workshop Summary

- Paper #3: How We Perform Field Assessment of Coatings
  - Field assessment of coatings should be performed during routine excavations
  - Test methods and procedure were presented
  - Some interest in industry database
  - A one page checklist was presented

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Coatings Workshop Summary

- Paper #4: How We Select Coatings for High Temp. Pipelines
  - Increased need for high temperature pipeline coatings (>85C)
  - No industry standards currently exist for testing or application of high temperature coatings
- Paper #5: Achieving Field-Applied Girth Weld Coating Quality
  - Industry requires a framework for applicator training and qualification
  - Field applied coating requirements to be included in CSA revisions

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Coatings Workshop Summary

- Paper #6: Select and Apply Repair and Rehabilitation Coatings
  - Coating selection is dependant on pipeline conditions including temperature, coating type, and ambient temperatures
  - Each repair method requires documented procedures, applicator training and quality assurance
- General Conclusion
  - A coatings discussion group should be establised to enable ongoing improvement
  - Overall it appears that selection, application and quality control are improving due to increased awareness.

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Working Group 7 - Pipeline Risk Assessment / Risk Management

Wednesday, April 11, 2001, at 1:30 p.m.

Co-chairs: Iain Colquhoun – Pipeline Integrity International
Leo Jansen – National Energy Board (absent)

Facilitator: Anton Walker – Suncor Energy – Oil Sands Group

Rapporteur: Nathan Len – National Energy Board

Session Objectives:

- To provide an interactive forum where the management of the integrity, safety, and risk of the pipeline infrastructure can be discussed.
- To facilitate and promote the sharing and exchange of information and the development of pipeline industry communication networks.
- To recognize areas where coordinated efforts can be implemented to enhance risk management as it relates to pipeline integrity management.

Speakers:

Speaker 1: ***Robert Sutherby – TransCanada PipeLines***
Title: ***PRASC Database***
Summary: There is an initiative to develop a common set of risk definitions that will be included in the next release of CSA Z662. In parallel to this, an industry database is being developed to provide industry with meaningful statistics on Canadian pipeline incidents.

Speaker 2: ***Brian Rothwell – TransCanada PipeLines***
Title: ***Failure Frequency***
Summary: Risk analysis, a primary component of risk management, requires the identification of hazards and the assessment of the frequency and consequences of specific hazard scenarios. The overall estimation of risk requires partial frequencies, by failure severity and mechanism, to be combined with the corresponding consequences (with their contingent probabilities). Estimates of frequency, for each severity level and mechanism of failure, can in principle be developed on the basis of historical data, mechanistic models, expert opinion or a combination of all.

Speaker 3: ***Graeme King – Greenpipe Industries Ltd.***
Title: ***Consequence Estimation and Modeling***
Summary: The consequences of a leak or rupture of a pipeline can be classified under the following headings:

- Life Safety
- Customer Impact
- Public Perception
- Environmental Impact

- Financial Impact

Speaker 4: ***Iain Colquhoun – Pipeline Integrity International***
Title: ***Decision Model and Implementation***
Summary: To develop an integrity program that balances safety, reliability, and profitability, we may start by applying constraints:

- Individual and societal safety risk thresholds
- Environmentally responsible programs
- Compliance with all applicable codes

Does the net present value of the risk reduced (expressed in equivalent dollars) over the anticipated benefit horizon exceed the cost of the lowest cost program to address the risk? When the proposed program is put together, what is the estimated residual risk? Is this acceptable? Once these questions are addressed a finalized integrity management program can be put together for the general pipeline maintenance program and field implementation in the most efficient manner possible.

Speaker 5: ***Iain Colquhoun – Pipeline Integrity International***
Title: ***Life Cycle Considerations of Integrity Management***
Summary: Managing the integrity of pipeline systems is a challenge, considering the limited and reduced resources and the pressure of striving for maximum return to shareholders, combined with aging infrastructure. Some questions to be discussed include: How can risk management assist in managing pipeline integrity? Is risk management simply an analytical approach to justify allocation of resources and selection of equipment and duties, or is it an effective tool or mechanism that is used (or can be used) by the pipeline industry to address the many challenges faced by them. An open forum will be held to discuss how risk management can be used in the management of pipeline systems. Discussion should consider how companies address pipeline integrity from "cradle to grave", i.e. from conceptualization and design of a pipeline system, operations through to decommissioning of the system. Is risk management an effective tool to help manage pipeline integrity?

Note: ***Refer to presentation slides for the specific contents of the presentations***

Open Discussion Summary:

General Statements on Risk Assessment/Management in Industry

- Before we try to determine how safe is safe enough, we need to look towards continuous improvement and use risk analysis to move towards system improvement.
- To determine the acceptability of risk, the industry needs to look at both frequency and consequence. Regulators are already looking at the consequence side. There was a consensus given that industry needs to improve on the frequency side of things.
- If you keep track of historical consequences of incidents, what is to say that they will be applicable to most areas where future failures may take place?
- One method of managing risk is to develop a risk profile for the system in its current state. Determine what the risk profile would be if the pipeline was brand new. Then work to bring the current profile closer to the profile of the new state.
- Define what is an acceptable risk. If you are trying to totally eliminate risk, there comes a point when the amount of money spent on maintenance is disproportional to the benefits that you receive. Even if an infinite amount of money is spent, there is a limit where safety is no longer improved.
- EUB data is available but at a considerable cost. This data then has to be combined with a company's own data to perform a meaningful analysis. Data should be more readily available with a decreased cost so that it can be used universally.
- EUB is looking at environmental database to make it more accessible. Will be looking at pipeline database to make user friendly. They will try to link their efforts with the PRASC database initiative.
- You have to look at risk on two methodologies – quantitative and qualitative. The most effective systems use a combination of both.
- There is a definite learning curve associated with risk management in industry. We are starting to see a better acceptance and use of risk management techniques by industry.

Specific Issues or Questions

Pipeline Risk Assessment Steering Committee (PRASC) Initiative

- At this point, the PRASC database is just a concept. Input is needed in order to ensure that the entire industry is covered.
- Working with sensitive data is a private issue, not a public issue. There is a need to keep most information public but keep sensitive information anonymous.
- A lot of effort is needed to manage a database of this type.
- In order for companies to see an added value of participating in databases, the data has to be broken down into meaningful data
- The data that you are keeping has to be aligned with what you are trying to achieve. We need to plan the database correctly so that everybody can use the same data.

What would you like the PRASC database to be able to answer? (What would you like to use it for?)

- Looking for trends in the information on factors that might influence failures (e.g. corrosion, pipe diameter, wall thickness etc.). This could be used to see what areas should receive increased attention. This information could also be used in the design stage as one may be able to determine how certain factors might affect the future reliability of the pipeline.
- Should be used to normalize data within the industry. This could then be used to perform a reality check on industry beliefs.
- Should be used to provide a benchmark to what companies could compare themselves to determine how they rate against other companies in the industry.
- Could be used to fine-tune regulatory programs and standards. This may lead to increased attention to certain issues and decreased emphasis in other areas.
- If the database is well thought out and developed properly, it could be used to develop best practices within industry.

How do we handle the risk of fatalities?

- Traditionally, it has been considered a faux pas to speak to the public about life loss and the dollar value associated with it.
- When quantitative analysis is done, the value that is assigned to people is actually the cost avoidance issue rather than the cost of the fatality itself. This area needs clarification so that people are talking about the same thing.
- Industry considers assigning a value or probability to people is acceptable (risk). The perception of the public is that living by pipelines is an imposed risk. The public is not willing to accept any probability of risk when it comes to people. Companies need to try to come up with rational before taking the risk plan into the public forum. The goal is for the industry to be transparent to the public but it must be realized that crossing over the threshold can be problematic. This addresses another issue other than risk management: risk communication. A possible solution is to have a communications expert portray the information to the public rather than the engineer or technical person.
- A concern is that the information that is viewed by the technical people may fall into the hands of a person without the appropriate background knowledge. As a starting point, there is a need to inform people within company as to what the information is and how to interpret it.
- Within the industry there appears to be a tendency to withhold information between one another (between colleagues, regulatory officials etc.) Companies need to become transparent (open to each other) within industry before they can achieve the goal of being transparent with the public.
- Possibly shippers and regulators should have a role in assigning the cost associated with people. This could then be adopted in company risk models.
- Other industries may have the same problems. Someone should look towards other industries with respect to how they quantify risk with respect to fatalities. Some other industry may have already done something similar (e.g. Chemical Process Industry, Airline, Rail Transportation, Health Care).
- If we don't assign a value to people we may not be able to come up with an indicator to determine when safe is safe enough.

- With regards to absolute or quantitative risk, it is very difficult to assign a risk value to capture your gut feeling of how the people living along the pipeline feel.
- Costs associated with incidents are business decisions. This is different than when you are talking about fatalities. This is where the risk value gets very shaky. Most people want to avoid assigning value to human life. The problem is in trying to determine what is acceptable. This may prevent proper risk assessment when dealing with people.

How do you proceed to get more resources allocated to an integrity program?

- You usually have a better chance at convincing your company to an increase in funds towards integrity if there is a real example to be seen. Other justifications seem to go unnoticed. (Some participants said their experience was that the best way to avoid such "knee jerk" reactions was through the use of an impartial risk management approach).
- The occurrence of major incidents (ruptures etc.) has an effect on how much a company is willing to spend on integrity management. The reason for this is the increased awareness into the problems themselves as well as the severe consequences associated with a similar incident.
- One good justification for additional resources is to try to reduce the frequency of occurrences
- Any resources have to be justified on a cost/benefit analysis. This is needed to justify reasons to company officials.
- Quantitative models make it easier to demonstrate to company officials the benefit of allocating resources to a certain area.
- To get more funding, the risk assessment would have to indicate a greater level of risk exposure than was previously understood. The quantitative analysis needs to seem reasonable (it must stand up to reality)
- On the upstream side, expenditures are being justified using risk models. Routinely, decisions are made using pure risk management. This has been happening since the early 1990s.

Can risk management be used to lower insurance premiums for facilities?

- With regards to service facilities, insurers have been asked that question. There seemed to be some indication that there was potential for the underwriters to start looking at the issue.
- The first reaction from the insurance companies is usually no. With some pushing, it was found that there may be some opportunity for movement in insurance premium.
- It must be taken into account that the reduction in insurance premiums would probably not be very significant. However, the greater benefit lies within optimization of integrity program expenditures.
- Generally, insurance companies do not conduct studies such as risk assessment on the pipeline facilities that they are insuring. The questions that are asked when insuring a pipeline do not usually reflect the condition of the pipeline.

What now?

- PRASC still continue to gather comments on how to approach the issues so that the entire industry is represented.
- Need to clearly understand PRASC initiative and communicate it
- Discussion is improving towards the issue of risk assessment/management. Learning needs to continue.
- There is significant improvements being made in the level and consistency of discussions on risk. The path ahead must include continuation of industry wide dialogue.

What next?

In an ideal world:

- Regulators would understand methodology and mitigative methods used by companies
- Public would have some form of understanding and accept methods used for risk management
- People within own companies need to understand methodology and mitigative methods

Summary, Conclusions and Recommendations from the Session

- ***Pipeline Risk Assessment Steering Committee (PRASC) Initiative***
  - Possible uses of database were suggested
- ***How do we handle the risk of fatalities?***
  - Value of life/ALARP
- ***How do you proceed to get more resources allocated to an integrity program?***
  - Effect of major incidents
  - Use of impartial Risk Management approach
- ***Can risk management be used to lower insurance premiums for facilities?***
  - Yes (qualified)
  - Eclipsed by benefit in optimized integrity program
- ***What now?***
  - Move ahead on databases
  - Continued dialogue on risk
- ***What next?***

  In an ideal world:
  - Regulators would understand methodology and mitigative methods used by companies
  - Public would have some form of understanding and accept methods used for risk management
  - People within own companies need to understand methodology and mitigative methods

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Implementation of Pipeline Risk Assessment
CSA & PRASC
Robert Sutherby
TransCanada PipeLines

Pipeline Risk Management

- Risk Management is an effective tool to assess, evaluate, prioritize and mitigate risks
- Two bodies involved in implementing risk-based integrity management practices: CSA & PRASC
- Goal of improving and demonstrating the safety of pipeline systems through implementation of risk-based practices

RM Implementation

- CSA Z662 Appendix B on Risk Assessment
- CSA Z662 2003 ed. - Risk Data Dictionary
- PRASC Risk Data Base - 2003

Risk Data Base

- An industry-wide data base tool to support pipeline risk management
- Standardized and consistent risk terminology
- To improve, demonstrate and communicate the safety of pipeline systems
- By capturing and developing incident statistics in terms of frequencies and consequences

Design Criteria

- To ensure a successful design and implementation
- To identify objectives, needs, advice and design criteria from potential future stake-holders
- Scope ?
- "Incident" definition ?
- Consequence types ?
- Opportunities and Concerns ?

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Failure Frequency
Brian Rothwell
TransCanada PipeLines

Meaning of frequency

- For the purposes of risk analysis of pipelines:
  - Quantitative
    - "number of times that a given scenario is expected to occur, per unit of time and pipeline length"
  - Semi-quantitative
    - "comparative likelihood that a given scenario will occur, per system and unit of time"
      - "system" has a special meaning, defining the scope of the analysis
      - "frequent-occasional-unlikely-remote-improbable-hypothetical" is an example of a comparative scale of frequency

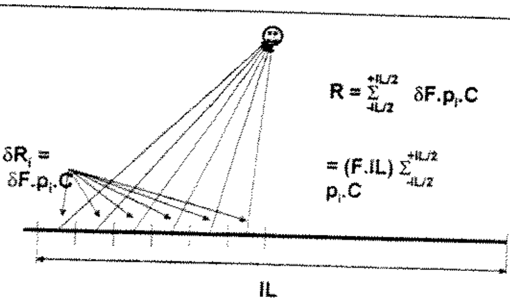
Frequency estimation

- Frequency of what?
  - Hazard scenario - e.g. leak (size), rupture
  - By hazard cause - e.g. corrosion, mechanical damage, ground movement
- Approaches
  - mechanistic models
    - reality check with historical data
  - historical data
    - appropriate database
  - combination of both
    - attribute-related modifiers for gross statistical data

Frequency estimation-challenges

- Relate frequency of scenario to attributes of pipe and its surroundings
  - resolution appropriate for purpose
- Recognize uncertainty and its influence
- Data management
- Lack of appropriate and widely available data
  - temptation to use data that's inappropriate
  - efforts to develop a Canadian database
- Lack of appropriate and widely available models

Frequency and consequence cannot be separated even if frequency is constant



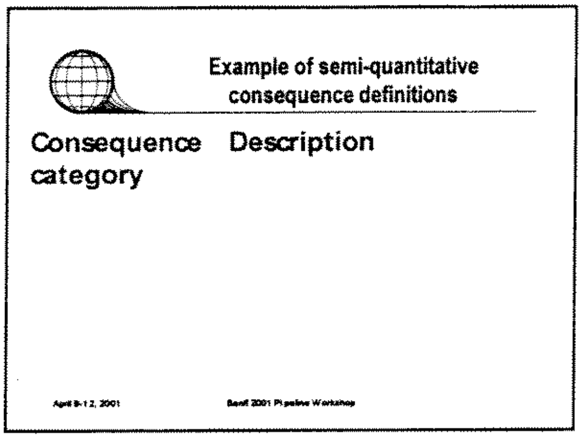
$$R = \sum_{-IL/2}^{+IL/2} \delta F.p_i.C$$

$$= (F.IL) \sum_{-IL/2}^{+IL/2} p_i.C$$

IL is only known when p_i has been analysed, or when limiting hazard range has been established

Example of semi-quantitative frequency definitions

Frequency category	Description


Example of semi-quantitative
consequence definitions
Consequence category
Description

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Consequence Estimation and Modeling
Graeme King
Greenpipe Industries Ltd.

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Factors Affecting Impact

- Settlement of claims for damages
  - Community (loss of life, injury, property damage)
  - Employees (loss of life, injury)
- Environmental impact
  - Cost of cleanup
  - Irreparable damage to wildlife and physical environment
- Regulatory penalties (fines, shutdowns, inquiries, etc)
- Service interruption (costs to shippers & customers)
- Loss of corporate image/public perception
- Cost of repairs

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Trends in Quantifying Impact

- Three broad approaches:
  - Qualitative or "zero-tolerance" (leading to prescriptive plans)
  - Semi-quantitative or factored (leading to risk matrix)
  - Absolute quantitative (dollar value and direct comparison)
  - Eclectic strategies (any combination of the above three)

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Trends in Quantifying Impact

- Good record keeping
  - Location of pipeline assets wrt rivers, roads, populated places, environmentally sensitive areas, etc. (GIS & GPS)
  - Record anomalies & defects as part of inspection tasks
  - Record remediation of anomalies and defects
  - Easy to use and auditable

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Discussion

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Risk Assessment / Management

- Learning curve in industry - starting to see a better response from industry towards risk
- Need consistent, meaningful data in order to reach what you are trying to achieve
- Availability of Data?
  - PRASC, EUB, NEB etc.
- What is the purpose of the PRASC Database?
- How do we handle the risk of fatalities?
  - Do we need to put a value on human life?
  - Can we address the risk by specifying a low probability of fatalities (constraint)

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Risk Assessment / Management

- Where do we go next?

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Life Cycle Considerations of Integrity Management

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Life Cycle Considerations of Integrity Management

- How can Risk Management assist in Managing P/L Integrity?
- Consider each phase in the Life Cycle of Pipelines:
  - Conceptual design
  - Detailed design
  - Operations and Maintenance
  - Emergency Preparedness and Response
  - Decommissioning
  - Final Cleanup

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Life Cycle Considerations of Integrity Management

- In practice, how has Risk Management been used to justify:
  - funding
  - people resources
  - purchasing specialty equipment
  - activities, programs or processes

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Life Cycle Considerations of Integrity Management

- Considering the Lifecycle of Pipelines, how can Risk Management be effectively used in Managing Pipeline Integrity?
  - include risk identification and prioritization used regularly in each phase of the pipeline lifecycle
  - make decisions based on risk (real and perceived)
  - consider short and long term impacts/effects (focus on lifecycle)
  - proactively manage integrity based on risk
  - other???

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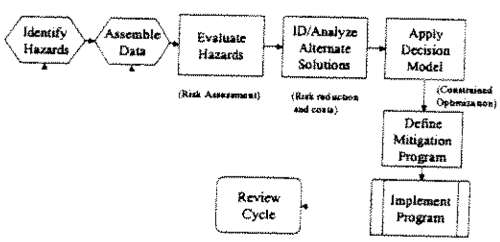
Decision Model and Implementation
Iain Colquhoun
Pipeline Integrity International

So What?

We have:
- Identified the Hazards
- Estimated the Failure Frequencies
- Calculated the Consequences
- Assessed the Risks
- Ranked Projects by Risk
- **So What?**

Pipeline Integrity Program High Level Process Flow

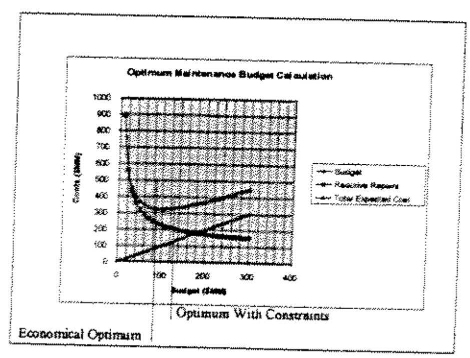


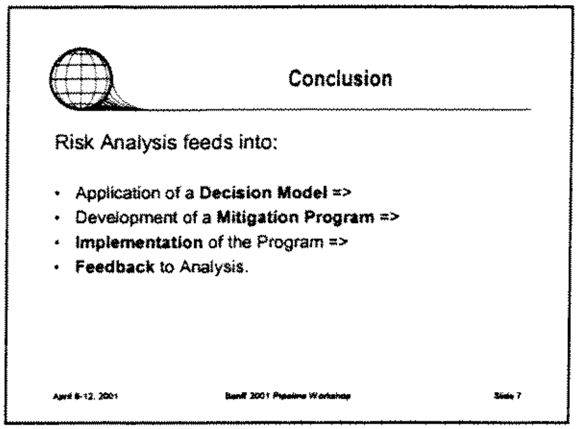
Apply Decision Model

- The Decision Model defines how the line can be operated **SAFELY**, **RELIABLY**, and **PROFITABLY**. It includes the following elements:
  - Constraints to be applied (Safety, Code, Environmental, Operational/Strategic etc)
  - Benefit/Cost criteria (Value Ratio)
  - Logistics and project groupings

Value Ratio

$$VR = \frac{\textbf{NPV Risk Reduction \$}\text{ (Safety, Environment, Customer, Direct Financial Impact)}}{\textbf{Project Cost \$}}$$




Conclusion
Risk Analysis feeds into:
• Application of a **Decision Model** =>
• Development of a **Mitigation Program** =>
• **Implementation** of the Program =>
• **Feedback** to Analysis.
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Slide 7

Managing Pipeline Integrity: Pipeline Risk Assessment/Risk Management
April 11, 2001 1:30 p.m. - 5:00 p.m.

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88	NorCorr Eng. Ltd	Mylos Artym	403 531-1966	mylos@norcorr.com	[signature]
89	GAS Technology Institute	Harvey Haines	847 768-0891	harvey.haines@gastechnology.org	[signature]
90	MARR ASSOCIATES	MARK JOHNSON	403-258-2233	mjohnson@marr-associates.com	[signature]
91	KOMEX INTERNATIONAL	FRED CLARIDGE	403-247-0200	fclaridge@calgary.komex.com	[signature]
92	TransCanada	DAN KING	403 920-6015	dan_king@transcanada.com	[signature]
93	CENTRA GAS	DON WALLACE	250-751-8319	Dwallace@centrabc.wei.org	[signature]
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BANFF/2001 PIPELINE WORKSHOP

Pipeline Risk Assessment / Risk Management

Workshop Discussion Summary

April 9-12, 2001 Banff 2001 Pipeline Workshop

Pipeline Risk Assessment / Risk Management

Workshop Discussion Summary

- ***Pipeline Risk Assessment Steering Committee (PRASC) Initiative***
  - Possible uses of database were suggested
- ***How do we handle the risk of fatalities?***
  - Value of life/ALARP
- ***How do you proceed to get more resources allocated to an integrity program?***
  - Effect of major incidents
  - Use of impartial Risk Management approach

April 9-12, 2001 Banff 2001 Pipeline Workshop

Pipeline Risk Assessment / Risk Management

Workshop Discussion Summary

- ***Can risk management be used to lower insurance premiums for facilities?***
  - Yes (qualified)
  - Eclipsed by benefit in optimized integrity program
- ***What now?***
  - Move ahead on databases
  - Continued dialogue on risk

April 9-12, 2001 Banff 2001 Pipeline Workshop

Pipeline Risk Assessment / Risk Management

Workshop Discussion Summary

- ***What next?***
  - In an ideal world:
    - Regulators would understand methodology and mitigative methods used by companies
    - Public would have some form of understanding and accept methods used for risk management
    - People within own companies need to understand methodology and mitigative methods

April 9-12, 2001 Banff 2001 Pipeline Workshop

Workshop Session 8 - In-line Inspection of Transmission Pipelines

Wednesday, April 11, 2001 at 8:30 a.m. – noon

Co-Chair: Steve Gosse, Westcoast Energy
Co-Chair: Arti Bhatia, Alliance Pipeline
Rappporteur: Don Engen, Enbridge

Outline:

1. State of the Industry Today - Harvey Haines (GTI)
2. Consideration and verification when inspecting for mechanical damage, dents and hard spots - Bruce Nestleroth (GTI) and Blair Carroll (Fleet Technology)
3. Treatment of Vendor Tool Performance Specifications for corrosion and crack detection - Tom Morrison (Morrison Scientific)
4. Tool Development and Research - Blaine Ashworth (TransCanada Pipelines)

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1. State of the Industry Today

Harvey Haines (GTI) presented a breakdown of research endeavors and tool development as it appears today. The presentation included in these proceedings.

David Katz from Williams Gas Pipeline - West asked for clarification as to whether the dents and/or mechanical damage was from the DOT Reportable Incident summary and the Kiefner report were determined to be construction defects or defects that formed during operation.

Harvey did not believe that any of the 31 incidents were due to rock dents.

Barry Martens from Rainbow Pipeline inquired about the nature of the failures with respect to multi mode defects i.e. corrosion within dents.

Harvey emphasized that most failures are not due solely because of a dent but associated cold working and cracking can contribute.

Barry Martens inquired about the shape of the corrosion defects used in the research of multi mode defects i.e. corrosion in dents.

Bruce Nestleroth responded that their all had smooth front edges.

Barry Martens commented that he had experience where the tool has missed certain defects and a failure has occurred.

Arti Bhatia polled the group as to how many operators have asked for POF (Pipeline Operator Forum) formats from the vendors as to their tool's capability and how many vendors have received requests from operators.

Chris Billington from BC Gas indicated that they were moving towards acquiring the specifications in this format however they did not have enough data points to reference back to as of yet.

Harvey Haines asked if operators were requested the POF format.

Daryl Ronsky from PII responded by saying that clients are asking for the format and in particular are raising questions about accuracy of sizing.

Dave Hektner from BJ Pipeline Inspection Services pointed out that Mapping/IMU has been around since 1988 and RTD Laser Technology is now available in the US. He pointed that the circumferential technology has been available since 1998. He also commented that inertial technology on MFL tools is working well.

Harvey inquired as to whether the tool referenced by Dave had an axial magnetizer with circumferential sensor technology.

Dave responded that they use the circumferential technology to better identify corrosion defects but it is not used to identify crack defects.

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2. Inspecting for Mechanical Damage

The group was asked if any of the operators would lime to comment on the use of circumferential MFL tools.

Blaine Ashworth (TCPL) replied that TCPL used the TFI (Transverse Field Inspection) tool for R & D purposes and it was difficult to detect and size low levels cracks.

Chris Hallam from BJ Pipeline Inspection Services asked if there was a different MFL signal for gouges on mechanical damage tools.

Bruce responded that the signal is different.

Harvey Haines pointed out the terminology for gouges need to be better defined.

Phil Nidd from Agra Monenco commented that 2400 excavations were conducted based on TFI data on the Platte system. A paper was presented at IPC 2000. He mentioned that they had some success manually differentiating dents with gouges and mechanical damage

Dave Katz commented that a tool would be useful if it was cost effective for identifying dents better such as top half defects instead of bottom since the DOT will be inquiring about prioritization of defects.

Steve Gosse asked about the Canadian experience with respect to mechanical damage instances.

A representative from Greenpipe Industries commented that Canadian pipelines were in less high-risk areas.

Deb Billey a contractor to Enbridge inquired about the multi level capabilities of MFL for detecting dents within welds.

Bruce Nestleroth that he had not done any work in that area.

Blair Carroll presented a few slides on planning rock dent excavations based on high-resolution caliper data, which is included in this package.

The group was asked if any of the operators were using various modes of tools and overlaying the data to prioritize their dent and other digs.

Shamus McDonnell from Hunter McDonnell replied that they had worked on different ILI tool data to find deformation type defects and the correlation to date was working good.

Blair responded that a three-dimensional FEA model would fine-tune the process of assessment that Shamus commented on.

Bruce Haggar from PII commented that one could differentiate on MFL data between greater and less severe defects but they could not see cracking within the dent and they generally gave customers the most severe dent information.

Blair commented that you can run a tool to determine the severity and get accurate information but dent prioritization is a staged process and operating conditions such as large pressure fluctuations could cause problems.

Brian Rothwell asked Blair to clarify in the dents Fleet had modeled were all greater that 6 percent.
Blair confirmed that the initial indentor was the number referenced on the chart but many of the dents rebounded to 6 or less percent so less that 6 percent dents had been modelled.

Bruce Nestleroth commented that there was a difference between Blair's and his work. Blair's was more representative of fatigue on dents with rocks and Bruce's was more focused on mechanical damage.

Frank Christensen from FM Christensen Metallurgical Consulting stated that he did not believe that the weld alone referenced in Z662 was considered a stress concentrator.

Blair commented that the research that Fleet had done did include the influence of the weld and such that the number of cycles to failure decreased with its influence.

3. Treatment of Vendor Tool Performance Specifications

Tom Morrison (Morrison Scientific) presented a few slides on why operators should validate their ILI tool runs. The slides are included in this package.

Phil Nidd commented the group as to whether we were moving towards a period of validating more stringently. How would the ILI vendor, the operator and an NDE company work to resolve measurement errors?

Tom replied that communication is the key and all parties have to work together to develop and stick to a project plan. He also said that field conditions play an important role in influencing accuracy. Modern technologies like the laser tool make it easier to get answers. Feedback to the vendor is key.

Bruce Nestleroth commented that the through the POF format there are eight categories of defect sizes. The operator should have a sense which tools will capture the defects in a more accurate fashion.

Phil Nidd asked if validation is recommended for each wall thickness.

Tom Morrison said yes to get confidence in your results more digs may be required.

There were no commented from the ILI vendors.

Harvey Haines felt that this is a big issue in the US and he asked Tom on his philosophy.

Tom emphasized that there are many configurations of corrosion and rather than conduct big laboratory research projects, the operator should be responsible for validating the tool on their own line.

Harvey Haines asked that if operator's used dig data, would there be enough data points to statistically validate.

Tom commented that the digs can be expensive and that mapping the corrosion accurately and gathering the most data was the first and foremost responsibility.

Bruce Haggar from PII commented that accuracy levels of data i.e. data interpretation may be improved if operators were cleaning and preparing the line more effectively.

Trevor MacFarlane from Dynamic Risk Assessment commented that caution should be taken when addressing multiple tool run data from different years and eras of tools to ensure accurate representation of growth.

Tom replied that both similar and different tools had been matched. Guy Desjardins commented that probability distributions re employed in their analysis.

4. Tool Development and Research

Blain Ashworth (TCPL) presented on TCPL's continued with the UltraScan CD tool and EMAT technology for crack detection. The slides are included in this package.

Bob Coote from Coote Engineering inquired about the differences on past EMAT development initiatives through PRCI and this tool.

Blaine commented that picking high wave mode frequencies that they overcame some of the earlier problems.

Bruce commented that wave mode selection is better today that in the past.

Harvey commented that the previous tool had a wave mode that was sensitive to coatings. The wave mode did not fulfill size and discrimination at that time.

Kyle Keith from Foothills Pipeline inquired if this EMAT tool would be as good as the UltraScan CD tool.

Blaine responded that the goal is to be equivalent. The resolution circumferential could be less due to wave mode.

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5. Conclusion

The group recognized that there had been some advancements over the last two years since the 1999 Workshop in many areas related to ILI tool technology development, detection capabilities and size availability.

BANFF/2001

In-Line Inspection of Transmission Lines

State of the Industry Today

Harvey Haines
Program Manager, NDE

gti

GRI/PRCI ILI Projects

- Mechanical Damage
- Corrosion
- Stress Corrosion Cracking
- Coating Disbondment
- Weld Defects
- Stress and Strain
- Unpiggable Lines

Why Build a Mechanical Damage "Smart Pig"?

- Initially the need to build a pig was based on:
  - incidents like Edison, NJ and Reston, VA, and
  - advice from pipelines that smart pigs were not discriminating all mechanical damage anomalies.
    - Not all Mechanical Damage is found
    - Mechanical Damage often yields very small signal on MFL "smart pigs"

Why Build a Mechanical Damage "Smart Pig"?

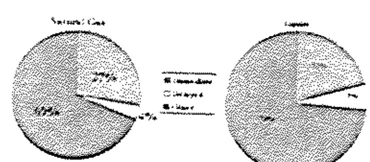
- In 1997 GRI advisors started asking how this tool would be best run?
  - Does it makes little sense to run an LI tool solely for Mechanical Damage?
  - The tool is designed to be an improved MFL tool to detect corrosion and mechanical damage
    - Pipelines currently run MFL tools for corrosion
    - An improved tool may reliably detect 3rd party damage.
- How effective is an improved tool going to be at reducing incidents?
  - A study was commissioned with Kiefner & Assoc. to determine potential tool impact.

Kiefner Report

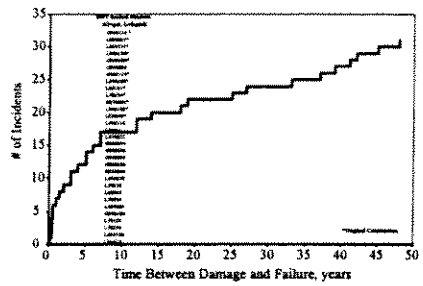
- GRI-99/0050
  Effectiveness of Various Means of Preventing Pipeline Failures from Mechanical Damage
- Study examined DOT incidents from 1985-1997
- Number of incidents studied is 3719
  - Combining the DOT databases from both the Natural Gas Transmission & Gathering and Liquid Petroleum Pipeline databases.

DOT Reportable Incidents, 1985-1997

Pipelines	Incidents from all Causes	Mechanical Damage: Immediate Failures	Mechanical Damage: Delayed Failures	Rock Dent Failures
Natural Gas [illegible] 300,000 mi.	1084	[illegible] (26%)	40 (4%)	
Liquid Petroleum [illegible] mi.	2635	542 (21%)	130 (5%)	12 (0.5%)



How Long Between Damage & Failure?



Mechanical Damage In-Line Inspection Impact

- Improved ILI may reduce the number of reportable incidents by <2-3% out of the 4-5% of delayed incidents
- Improved ILI may help reduce some of the more prominent failures
  - Edison NJ & Bellingham WA were inspected with ILI
    - Small mechanical damage signal were not apparent until after the fact
    - Improved ILI might have helped prevent one or more of these incidents
  - These incidents are some of the most expensive incidents to pipelines
  - These incidents are have caused the significant exposure to the surrounding area

Future GTI–DOT work

- Battelle will study Circumferential MFL fields
  - Hope for better characterization of gouge region
  - Will also examine corrosion sizing & crack detection capability
- SwRI will integrate defect assessment with MFL and non-linear harmonics
  - Non-linear harmonics is a stress measurement using 3rd harmonics non-linearities to measure stress
- GRI continues to support Tuboscope in their Axial MFL development and commercialization

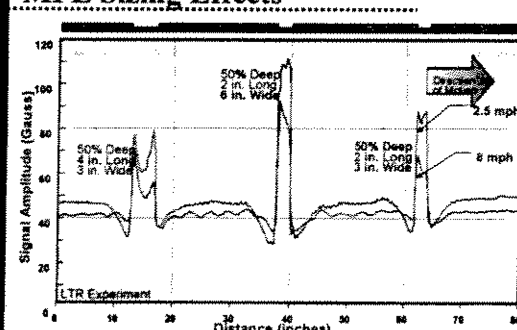
GRI/PRCI NDE Projects

- Mechanical Damage
- Corrosion
- Stress Corrosion Cracking
- Coating Disbondment
- Weld Defects
- Stress and Strain
- Unpiggable Lines

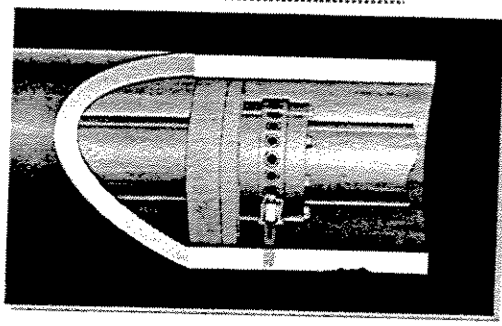
Corrosion

- Better Algorithms for Inverting MFL Signals to Corrosion Geometry (Depth, Length, Width)
  - GRI has transfered the results of its investigations to vendors (reports available)
- A Circumferential MFL Tool is Now Available from PII
  - Can inspect for seam weld corrosion and cracking
  - Will be investigating improvements from using both axial and circumferential fields
- Working on Gas Coupled Ultrasonics
  - Long term effort to make Ultrasonic pigging work in gas pipelines

MFL Sizing Effects



Gas Coupled Ultrasonics



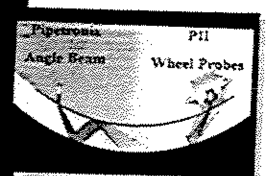
GRI/PRCI NDE Projects

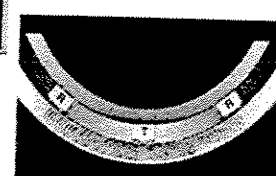
- Mechanical Damage
- Corrosion
- Stress Corrosion Cracking
- Coating Disbondment
- Weld Defects
- Stress and Strain
- Unpiggable Lines

Stress Corrosion Cracking

- Ultrasonics
  - Guided Wave
    - PII – Elastic Wave Vehicle
    - TDW – EMATs
  - Near Field Imaging
    - Pipetronix – UltraScan CD
    - Phased Arrays
- Electromagnetics
  - Magnetics
    - Circumferential MFL
  - Eddy Currents
    - Self Excited Eddy Currents
    - Remote Field Eddy Current

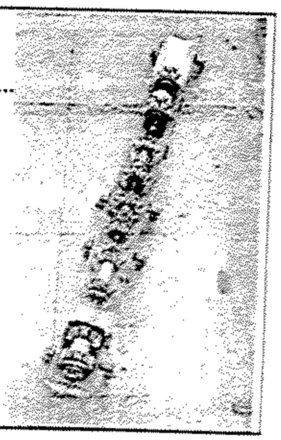
Ultrasonic Crack Inspection Methodologies



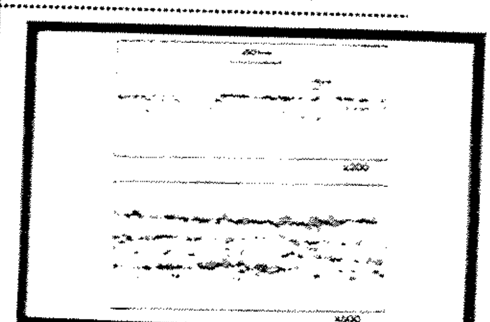


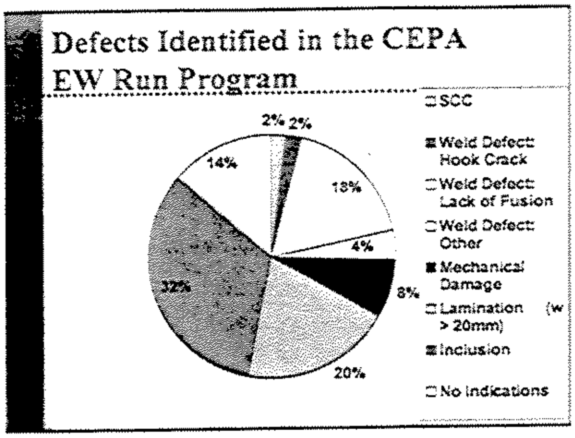
PII 24" diameter Elastic Wave Vehicle

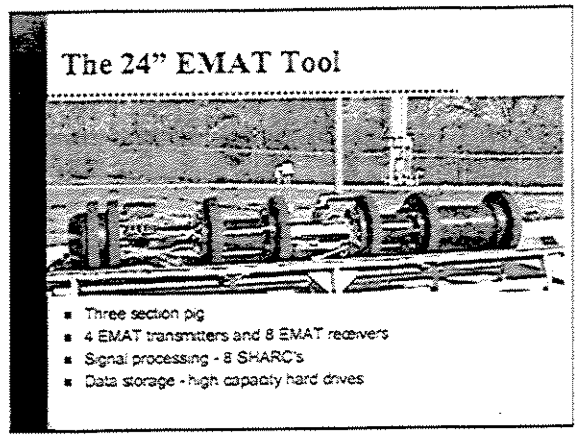
- 36" tool has been run many times in Canada
- 24" & 30" tool has been run a few times in US

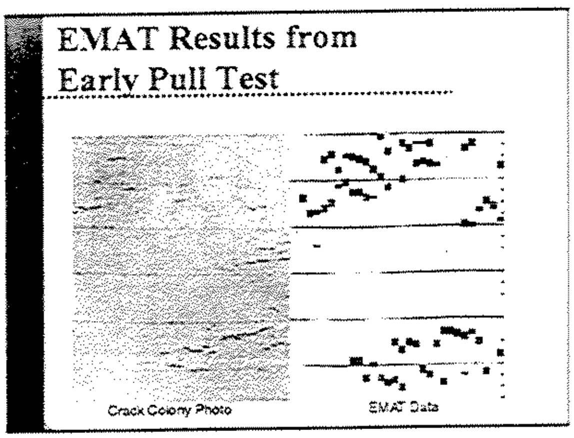


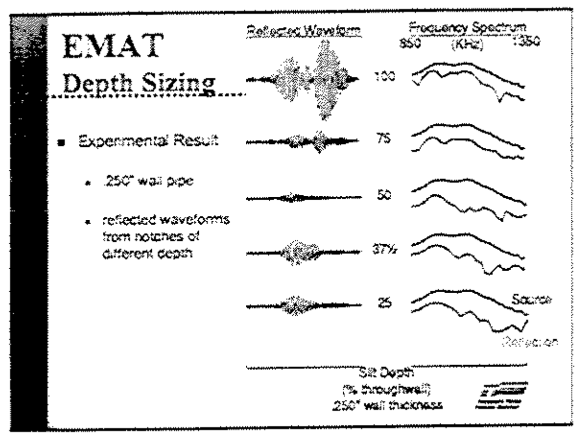
NON - SCC Inclusions

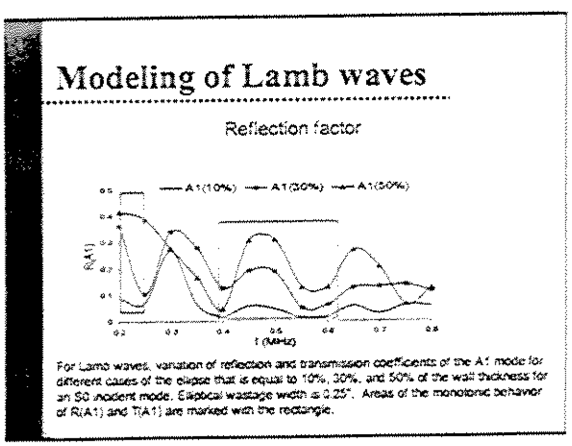


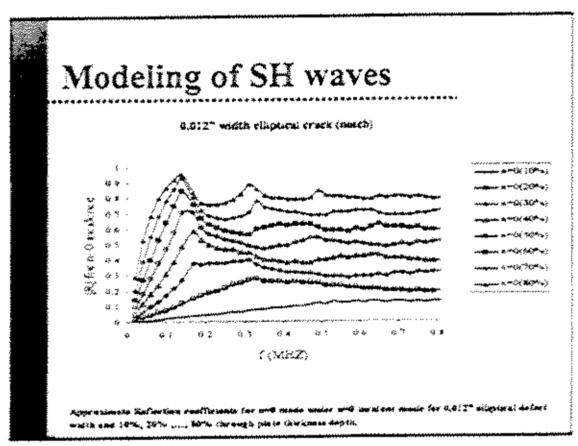

Defects Identified in the CEPA EW Run Program
2%
2%
14%
13%
4%
8%
32%
20%
SCC
Weld Defect: Hook Crack
Weld Defect: Lack of Fusion
Weld Defect: Other
Mechanical Damage
Lamination (w > 20mm)
Inclusion
No Indications


The 24" EMAT Tool
Three section pig
4 EMAT transmitters and 8 EMAT receivers
Signal processing - 8 SHARC's
Data storage - high capacity hard drives

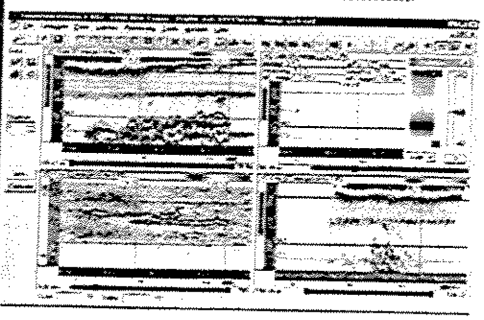

EMAT Results from Early Pull Test
Crack Colony Photo
EMAT Data


EMAT Depth Sizing
Experimental Result
.250" wall pipe
reflected waveforms from notches of different depth
Reflected Waveform
Frequency Spectrum
850 (KHz) 1350
100
75
50
37½
25
Source
Reflection
Slit Depth (% throughwall)
.250" wall thickness

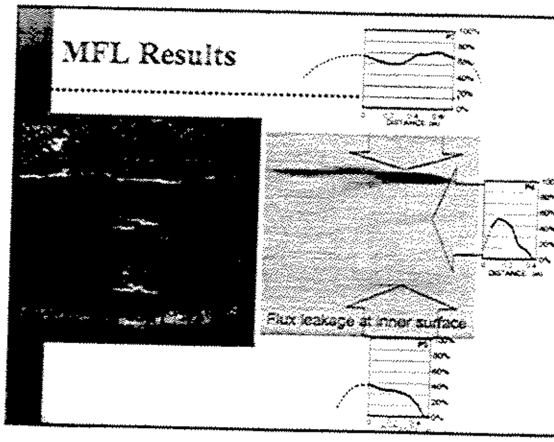

Modeling of Lamb waves
Reflection factor
A1(10%)
A1(30%)
A1(50%)
R(A1)
f (MHz)
For Lamb waves, variation of reflection and transmission coefficients of the A1 mode for different cases of the ellipse that is equal to 10%, 30%, and 50% of the wall thickness for an S0 incident mode. Elliptical wastage width is 0.25". Areas of the monotonic behavior of R(A1) and T(A1) are marked with the rectangle.


Modeling of SH waves
0.012" width elliptical crack (notch)
Reflection Coefficient
f (MHZ)

Phase Array Imaging of Cracks in the Lab



MFL Results



GRI/PRCI NDE Projects

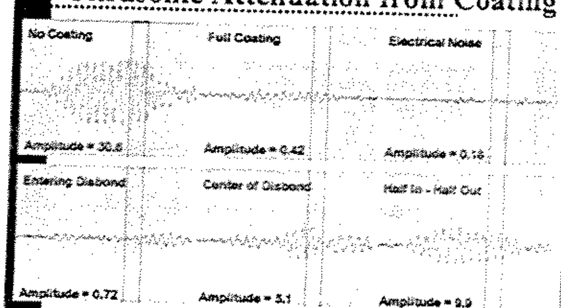
- Mechanical Dam age
- Corrosion
- Stress Corrosion Cracking
- Coating Disbondm ent
- Weld Defects
- Stress and Strain
- Unpiggable Lines

Coating Disbondment

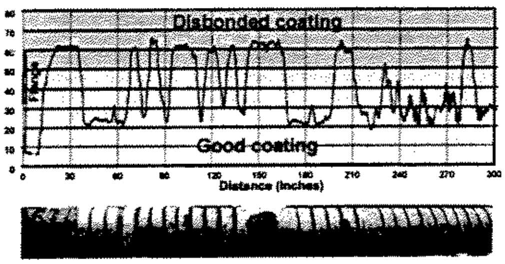
- PII – Elastic Wave Vehicle
  - Detect Coating Disbondment
  - Differentiate Different Types of Coating
- Battelle & NIST (PRCI Project)
  - Determine if an EMAT coil can be placed iran MFL magnetizer to detect coating disbonds.

Data from the Elastic Wave Shrink Sleeves Identified

Ultrasonic Attenuation from Coating



Example from NIST-Battelle Study



Inspection Techniques

- Mechanical Dam age
- Corrosion
- Stress Corrosion Cracking
- Coating Disbondm ent
- Weld Defects
- Stress and S train
- Unpiggable Lines

Girth Weld Inspection

- No ILI tool exist for inspecting girth weld in pipelines
- One Robotics tools w as developed by PG&E for inspecting girth w elds on out of ser vice lines
  - Technique used EMATs generating S_H waves

GRI/PRCI NDE Projects

- Mechanical Dam age
- Corrosion
- Stress Corrosion Cracking
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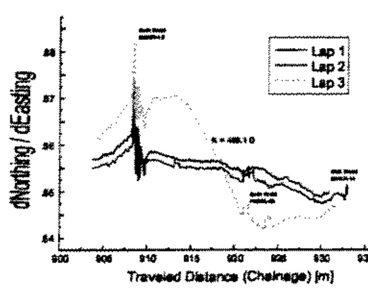
- Unpiggable Lines

Stress & Strain

- Indirect T echniques
  - Inertial navigation pigging (not a reseach issue)
    - Snam has performed studies
    - Vendors testing tools at the PSF
- Direct T echniques
  - MIVC (Magnetically Induced Velocity Changes)
    - Developing equipment that is portable enough to work "in-the-ditch"
    - Will probably be testing on pipelines in 2001 or 2002
  - Ultrasonic Shear Wave Birefringence
    - Currently working on laboratory techniques with NIST to measure stress differentials in pipes
  - Non-Linear Harmonics
    - Currently working on laboratory techniques as part of mechanical damage program

Inertial Mapping-Pipe Movement



Deflection on the pipe is visible in derivative of Northing over Easting in run 3, run 1 and 2 are without deflection

GRI/PRCI NDE Projects

- Mechanical Dam age
- Corrosion
- Stress Corrosion Cracking
- Coating Disbondm ent
- Weld Defects
- Stress and Strain
- Unpiggable Lines

Unpiggable Lines

- Significant Problems that Male Lines Unpiggable are:
  - High Speed Single Lines
    - Speed control
  - Laterals
    - No current solution
    - Need some sort of self powered robot
  - Undersized Valves
    - Collapsible Pigs
  - Plug Valves
    - No current solution
    - Remote Field Eddy Currents have been suggested, but no current research is active in this area

Conclusions

- Newer Technologies are Becom ing Available for In-Line Inspection of P ipelines
  - Corrosion
    - Better resolution with Magnetic Flux Leakage
    - Circumferential MFL for axial corrosion
  - Axial Cracking
    - Ultrasonics both imaging and guided wave techniques
    - Circumferential MFL is only good for large cracks
  - Mechanical Damage
    - Reduced Field MFL additions to MFL corrosion tools

Conclusion

- T here are many promising technologies for improving inspections
- I ha ve purposefull y not listed them in a concluding table because w e don't know which ones will be technicall y adequate or commercially successful

BANFF/2001
PIPELINE WORKSHOP

Inspecting for Mechanical Damage

Bruce Nestleroth, Battelle

Battelle

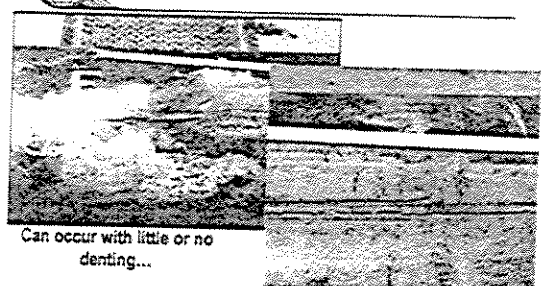
Presentation Outline

- Importance of Mechanical Damage – Why and when are mechanical damage defects important?
- Inspection Approaches to Finding Mechanical Damage – What tools are available or being developed now?
- Future Plans – What happens next?

Importance of Mechanical Damage

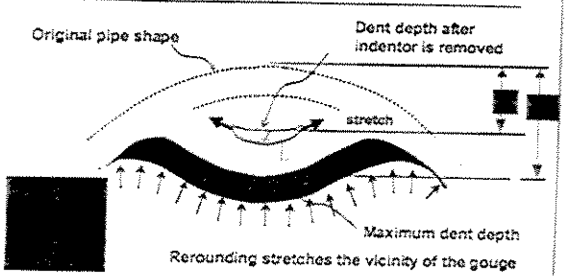
- How do we know which defects are important and which are not?
  - Smooth dents are less a of problem, unless very deep.
- What can lead to delayed failures in a mechanical damage defect?
  - Cracks.

Cracking Inside Gouges



Can occur with little or no denting...

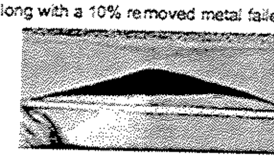
Rerounding



Rerounding stretches the vicinity of the gouge

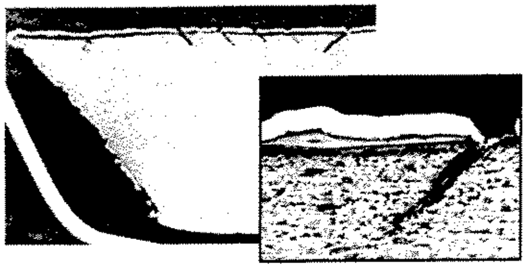
Pressure Rerounding

- The defect pipes were repressurized to reround dents
- A 6% dent, 6 inches long with a 10% removed metal failed at 80% SMYS



- The defect experienced 6 pressure cycles to 60% SMYS and one to 80% SMYS.
- Five crack fronts were observed.

Mechanical Damage Cross Section



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When Does Cracking Occur?

- When the microstructure under the gouge is damaged and subjected to significant tensile stresses due to pressure or rerounding
  - Depending on the indentor, we've seen cracking in many defects with a maximum depth (before rerounding) of 2 to 3 percent. We've seen some cracking in defects with maximum depths (before rerounding) of 1 to 1.5 percent and less.

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Inspection Approaches

- Caliper and dent-detection tools
  - Great for large rock dents
  - Requires a significantly different philosophy for third-party damage that may have cracks: examine all dents
  - Recognize that some gouges with cracking may have rerounded to a residual depth dent approaching zero; these defects will be missed
- Standard Magnetic flux leakage tools
  - Have found some mechanical damage, but not reliably

Can MFL be made more reliable and used to differentiate hazardous defects from benign defects?

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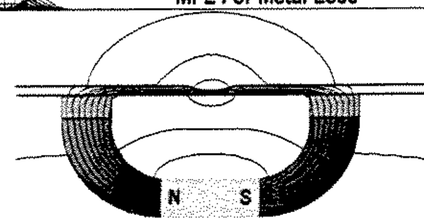
MFL For Metal Loss



Metal loss, such as corrosion, causes magnetic flux to be diverted outside the pipe.

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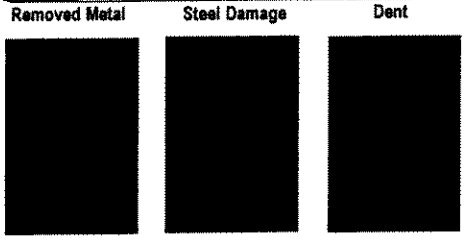
Unique MFL Signals from Mechanical Damage Components

Removed Metal **Steel Damage** **Dent**



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Causes of MFL Signals at Mechanical Damage Defects

- Removed metal causing the signal to increase
- Damage to the steel generally causes the signal to decrease if the magnetization level is low;
- Stresses and strains change the signals around the defect, and denting changes the orientation of the pipe wall relative to sensors – all of which further complicates the signals
- Cracks cause little or no signals

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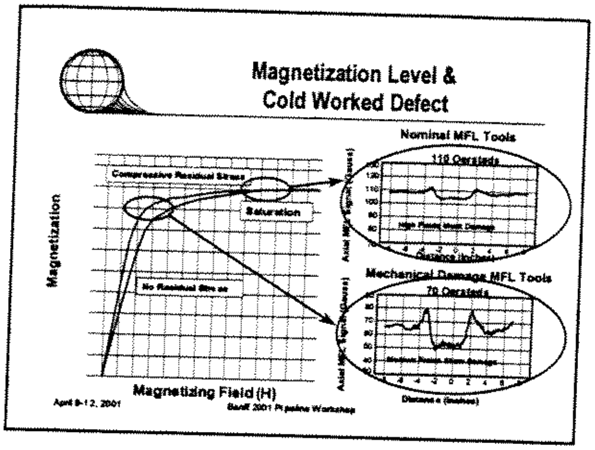

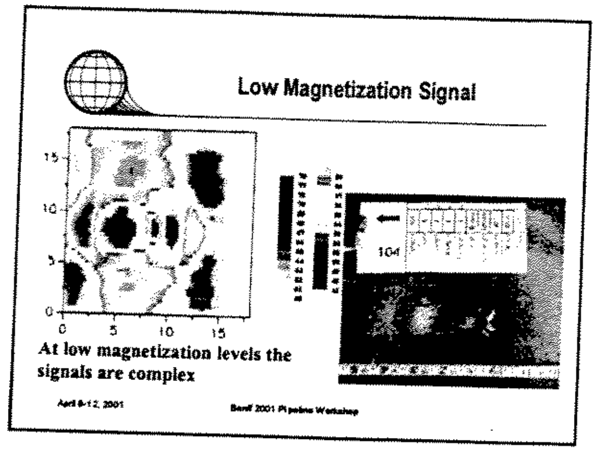

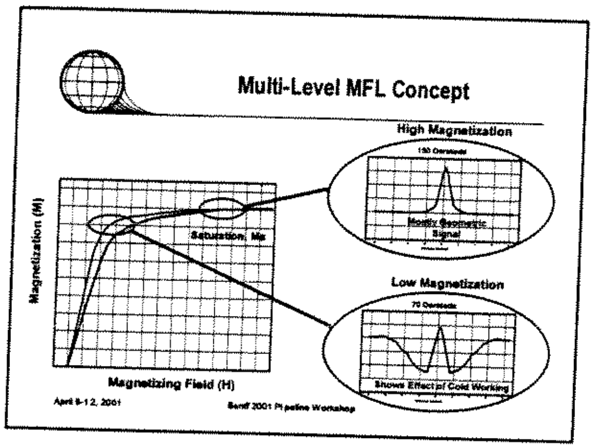

Multiple Magnetization Approach

- MFL signals at high magnetization levels are almost entirely due to geometry changes (moved and removed metal)
- MFL signals at low levels are due to both geometry and magnetic changes
- The difference is due to magnetic changes - the most important components of mechanical damage

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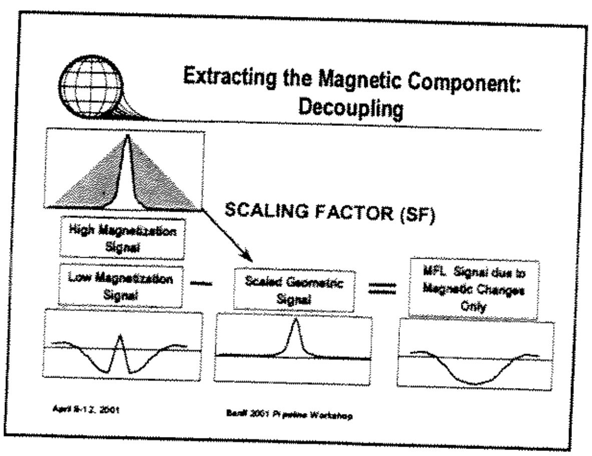
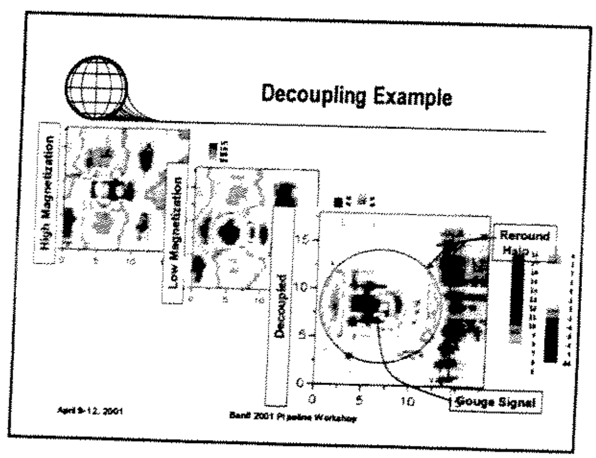
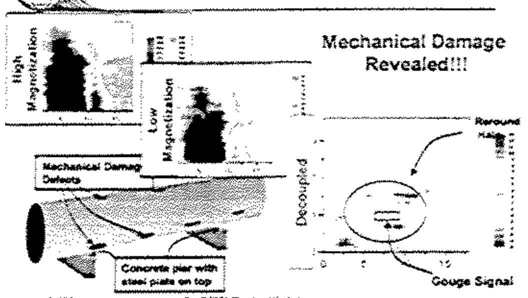




Demonstration that decoupling works



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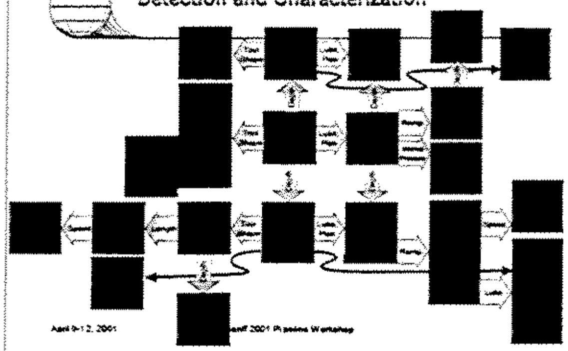
Defect Set Design for Assessment of Detection and Characterization



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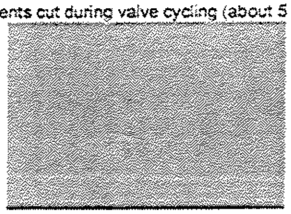
Typical Prior Defect Installation

- Defect installation took about a minute.
  - Movie at 10x speed
  - Segments cut during valve cycling (about 5 seconds)



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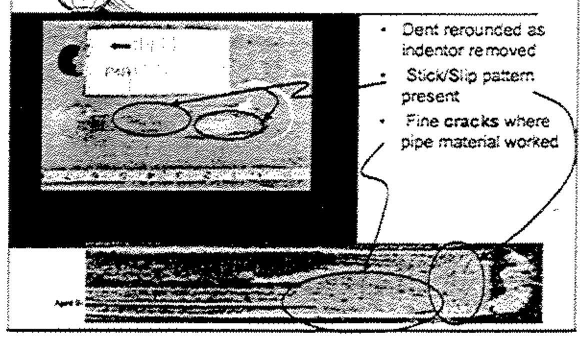
Machine Made Defects



- Dent rerounded as indentor removed
- Stick/Slip pattern present
- Fine cracks where pipe material worked

Inspection Goals (Significant Mechanical Damage)

- Detect
  - Mechanical damage with damage to the steel under the indentor
  - High stresses and strains in wake of indentor
  - Rerounding
  - Cracks
- Characterize
  - Degree and amount of damage to the steel and rerounding
  - Dent and gouge lengths

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Detection Analysis

- Decoupling the MFL signal reveals the presence of damage to the steel. A defect with damage to the steel yields a distinct signature in the decoupled signal.
  - The gouge signal shows regions of deformed, moved and removed metal
  - A reround "halo" shows regions that were deformed but no permanent deformation
- Decoupling increases the probability of obtaining a *measurable* signal from significant mechanical damage and properly differentiates these signals from other "anomalous" signals

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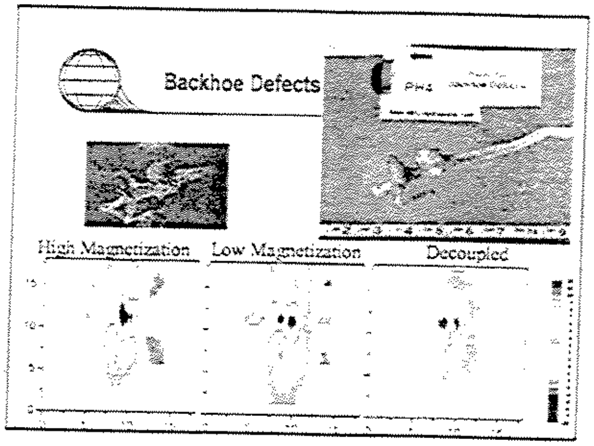
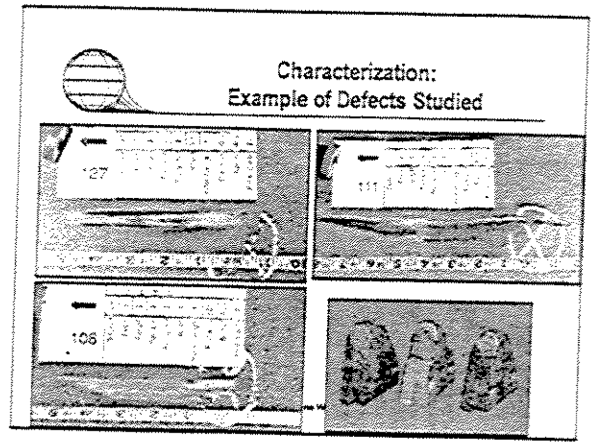
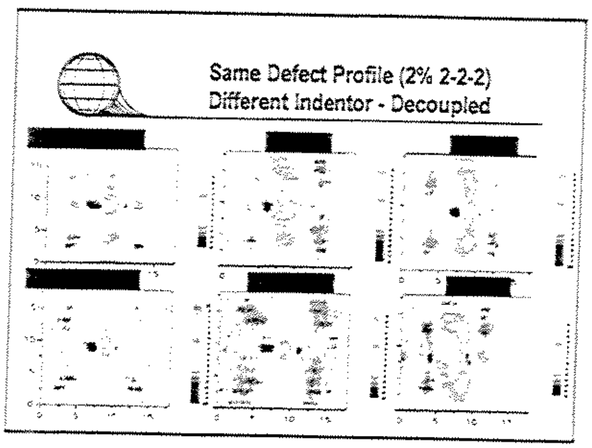
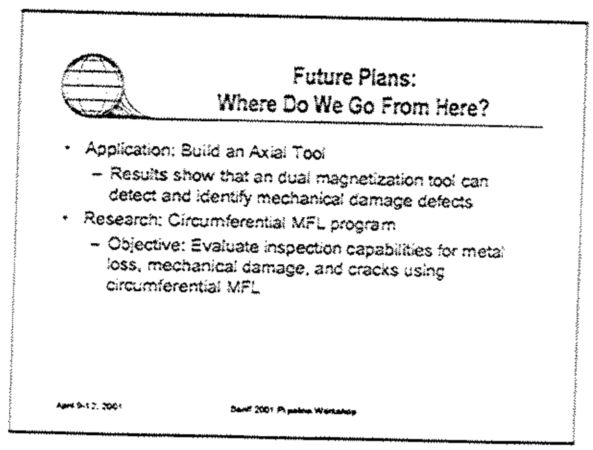

Backhoe Defects
High Magnetization
Low Magnetization
Decoupled


Characterization:
Example of Defects Studied
127
111
106


Same Defect Profile (2% 2-2-2)
Different Indentor - Decoupled


Future Plans:
Where Do We Go From Here?
• Application: Build an Axial Tool
– Results show that an dual magnetization tool can detect and identify mechanical damage defects
• Research: Circumferential MFL program
– Objective: Evaluate inspection capabilities for metal loss, mechanical damage, and cracks using circumferential MFL
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Planning Rock Dent Excavation Programs Based Upon High Resolution Caliper Tool Data

L. Blair Carroll
Fleet Technology Limited

April 9-12, 2001 — Banff 2001 Pipeline Workshop — FTL FLEET TECHNOLOGY LTD

Overview

- Planning rock dent excavation and repair programs based upon high resolution caliper tool data can be challenging
- The topics identified for discussion:
  - Tool validation
  - Repair considerations
  - Excavation program planning

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Tool Validation

- Validation of a high resolution caliper tool is a challenge
- Rock dents will usually experience some immediate re-rounding with removal of the overburden
- Further re-rounding may be evident as the line is subjected to a constant internal pressure in the absence of the overburden constraint
- Validation processes require a means of modeling these effects (Finite Element Analysis may be used)

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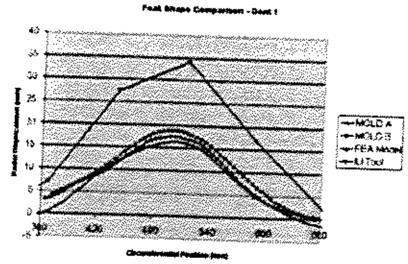
Tool Validation

Peak Shape Comparison - Dent 1



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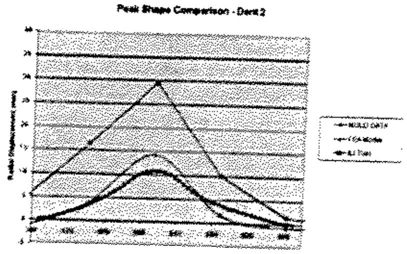
Tool Validation

Peak Shape Comparison - Dent 2



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Repair Considerations

- Codes consider dents defects when they meet one or more of the following requirements (CSA Z662-99):
  - The peak depth exceeds 6 mm (0.236 inches) in pipe with an OD less than 101.6 mm (NPS 4) or 6% of the OD in pipe larger than 101.6 mm in diameter
  - Dents that contain stress concentrators
  - Dents located on a mill or field weld and exceed 6 mm in depth
- Experience indicates that dents less than 6% of the OD may fail in service

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Repair Considerations

- Removal of the constraint applied by the indentor can actually lower the fatigue life of a dent
  - Implication: Dents that re-round to less than 6% of the OD may still require a repair (sleeve or cut-out)
- Will a reinforcement sleeve be effective in eliminating the potential for crack initiation and growth?
  - A pressure containment sleeve may be necessary

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Excavation Program Planning

- Methodologies required to rank dents on a priority list (similar to applying ASME B31G or RSTRENG to corrosion tool data)
- Numerical models developed to predict the severity of dents
- Caliper tool data should be correlated with corrosion and crack tool data
- Work underway to develop rapid characterization criteria

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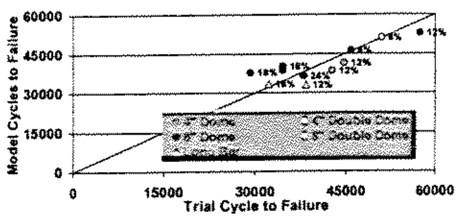
Numerical Modeling of Dent Life Expectancy

- Numerical modeling of full scale tests



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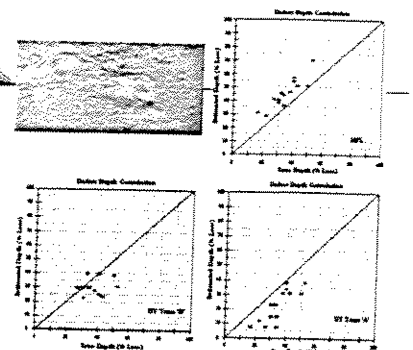
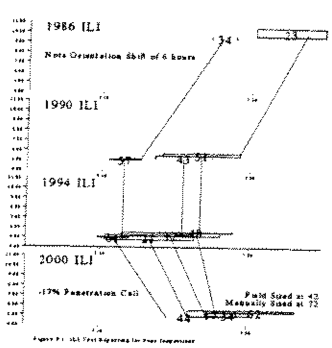
Treatment of Vendor Tool Performance Specifications for Corrosion and Crack Detection

Tom Morrison
Morrison Scientific Inc.



From: Drury and Marino, Rome 2000, 15th WCNDT



Why Should ILI Tool Corrosion Sizing be Validated?

- Every pipeline has a unique corrosion problem, therefore ILI tools should be validated for every pipeline and every type of corrosion.
- Estimation of measurement error is a very important cost saving methodology because understanding the tool's performance
  - may avoid unnecessary excavations,
  - aids in ready identification of potential leaks and ruptures.

Why Should ILI Tool Corrosion Sizing be Validated?

- By validating an inspection run any ILI tool reporting problems should become quickly evident.
- To verify the tool vendors claim of sizing accuracy for penetration, length and width. Failure/rupture pressure bounds are not typically included in a contract.
- Besides repeatability, there is a need to check overall bias and variable bias (systematic mis-reporting as a function of penetration, such as overestimating shallow features, and underestimating deeper features).

Why Should ILI Tool Corrosion Sizing be Validated?

- To determine whether ILI tool measurement error depends upon
  - feature geometry (complicated geometry being more troublesome for some tools to interpret),
  - density of the corrosion areas,
  - penetration of the feature.
- To determine whether there is a difference in ILI tool reporting between controlled (laboratory testing) vs. inspection conditions.

Why Should ILI Tool Corrosion Sizing be Validated?

- Knowledge of sizing accuracy is necessary for ANY prediction based on ILI data (such as growth modelling—see Working Group 10, Bob Worthingham and Trevor Place).
- To c heck whether the ILI tool is "blind" to a certain type of feature, such as Narrow Axial External Corrosion (NAEC).
- Automatic vs. manual interpretation of ILI tool reporting—how good is automatic vs. manual.
- Ne cessary as part of the process of developing new ILI tools.

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Why Should ILI Tool Corrosion Sizing be Validated?

- Engineers and researchers require an assessment of the possible measurement error in penetration and length for failure/rupture pressure calculations based on ILI and field tool reporting.

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Disadvantages of NOT Validating ILI Tools

- If the ILI tool is not validated, the ILI tool vendor and pipeline operator can have unnecessary disagreements as to the ILI tool performance.
- The pipeline regulatory agency has to understand that the pipeline operator and ILI tool vendor agree on the performance characteristics of the ILI tool.
- A non-validated or non-understood tool can lead to unnecessary excavations, or the omission of a repair that could have stopped a leak or rupture.

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Disadvantages of NOT Validating ILI Tools

- It is not possible to improve ILI tool performance if the ILI tool vendor does not receive feedback from the pipeline operator as to the tool's performance.
- After every inspection, some digs are done. Making digs enables a quick check of the ILI tool performance to be obtained, rather than having something wrong be discovered a long time later.

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Other Aspects of ILI Tool Validation

- Check False Positive and False Negative calls for cracks and corrosion.
- Incorrect orientation and/or odometer slippage—sometimes the feature someone is attempting to excavate can be on the other side of the pipe, and can be several metres away.
- Measurement errors are important as part of studying the relationship between ILI and field tool reporting. A regression line between an ILI tool and a field tool is not a valid relationship unless the slope is corrected by accounting for the measurement error of both tools.

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Other Aspects of ILI Tool Validation

- By having estimates of measurement error of ILI and field tools, if a comparison shows too large an error, reasons for the difference can be looked for. If things are wonky, a reason should be determined for the wonkyness.
- I LI tool should be validated with respect to field tool data, any available multiple inspection ILI data, and using both types of data if possible.

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Why Should Field Tools be Validated?

- Field tools are typically taken to be "perfect." The reason is that "the corrosion was right in front of my eyes." Beware, field tools can have large errors particularly if the conditions are bad, the corrosion is very complicated, and there are time constraints.
- Help s to compare different field tools.
- Validation o f field tools will help assess the capabilities of field tool operating personnel.

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Why Should Field Tools be Validated?

- If a field tool is not validated,
  - the measurement error of the field tool will be wrongly associated with the in-line inspection tool, which can lead to unnecessary excavations, ruptures or leaks,
  - it can lead to unnecessary refuting of the vendors contracted specifications, and
  - the regulator can call the inspection and maintenance programs into question.

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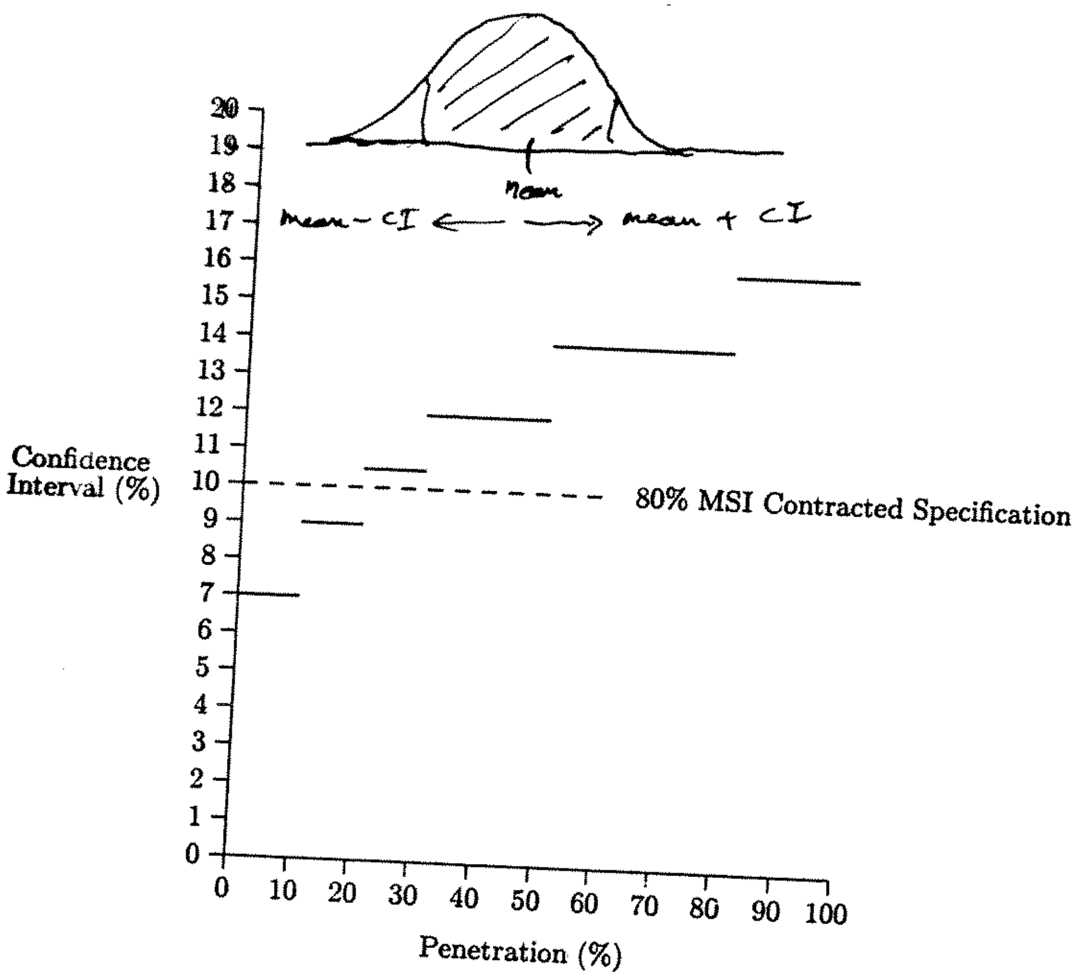
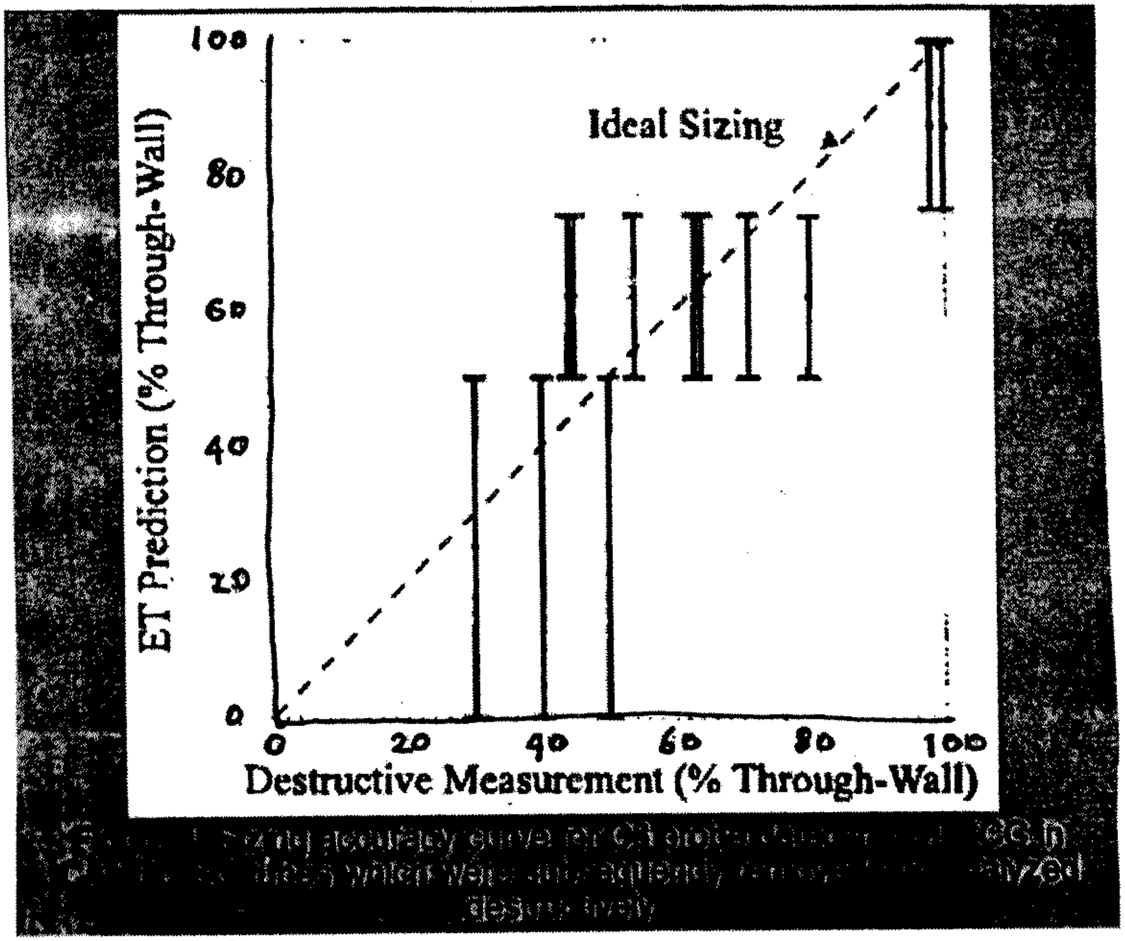


Figure 1.1: Measured vs. Contracted 80% Confidence Interval for Penetration for the Brand New Super-Duper High Resolution Morrison Scientific Inc. In-Line Inspection Tool



Sullivan et. al. Validating Eddy Current Array Probes for Inspecting Steam Generator Tubes

[redacted]

NDE Technique Capability Demonstration & Inspection Qualification
March, 1997

BANFF/2001 PIPELINE WORKSHOP

Tool Development and Research
Blaine Ashworth
TransCanada PipeLines

April 9-12, 2001 Banff 2001 Pipeline Workshop TransCanada

KEY RESEARCH AND TECHNOLOGICAL ADVANCEMENT REQUIREMENTS FOR ILI

Question

- What in-line tool research and technological advancements are next needed by pipeline operators?

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POLL FOR ILI TOOL ADVANCEMENTS THAT ARE REQUIRED

Improvements of:
- Caliper Tools?
- GIS tools?
- Mechanical Damage Tools?
- Corrosion Metal Loss Tools?
  - Extra Resolution?
  - Transverse MFL?
  - Multi-axis MFL?
- Crack Detection Tools?
- Other Tools?

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ULTRASCAN CD TOOL DEVELOPMENT - TIMELINE

1994 UltraScan CD Tool introduced by Pipetronix

1998 TransCanada ran UltraScan CD tool in 2 MLV sections

1998/2000 TransCanada investigated 40 Ultrascan CD features from 1998 runs.

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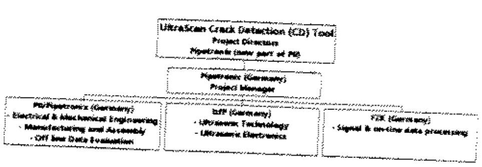
ULTRASCAN CD TOOL DEVELOPMENT TEAM

- Primarily Funded by Pipetronix
- Organization Chart for Development Team was:



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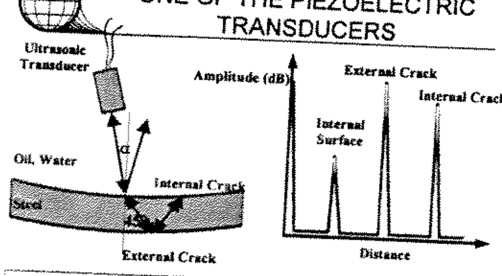
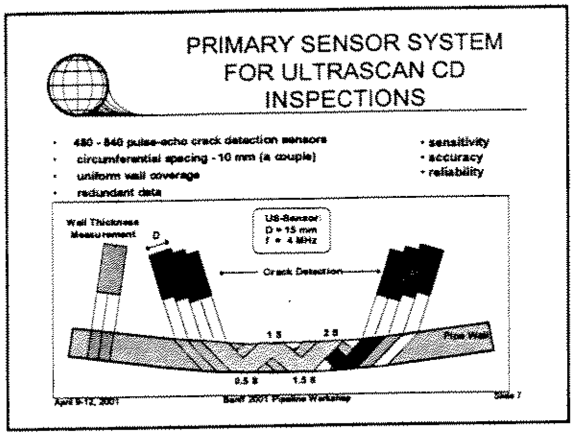
ULTRASCAN CD SIGNAL FROM ONE OF THE PIEZOELECTRIC TRANSDUCERS



Detection geometry (left) and corresponding A-scan (right)


PRIMARY SENSOR SYSTEM FOR ULTRASCAN CD INSPECTIONS
480 - 840 pulse-echo crack detection sensors
circumferential spacing ~10 mm (a couple)
uniform wall coverage
redundant data
• sensitivity
• accuracy
• reliability
Wall Thickness Measurement
D
US-Sensor:
D = 15 mm
f = 4 MHz
Crack Detection
1 S
2 S
Pipe Wall
0.5 S
1.5 S
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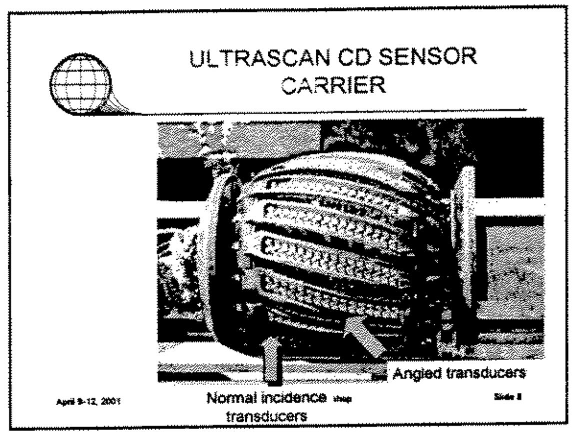
ULTRASCAN CD SENSOR CARRIER
Angled transducers
Normal incidence transducers
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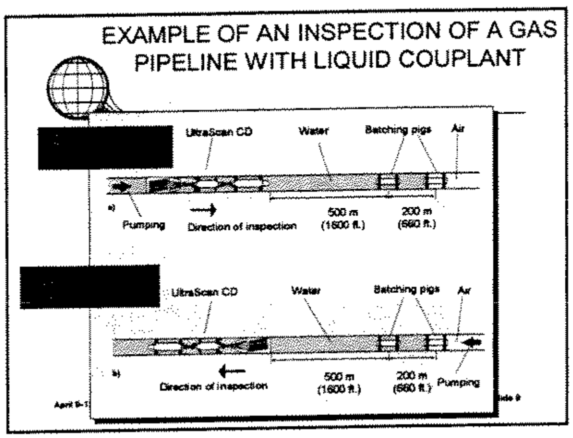
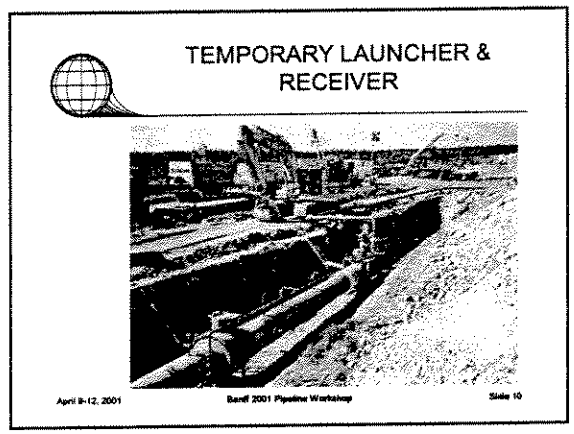

EXAMPLE OF AN INSPECTION OF A GAS PIPELINE WITH LIQUID COUPLANT
[redacted]
UltraScan CD
Water
Batching pigs
Air
a)
Pumping
Direction of inspection
500 m
(1600 ft.)
200 m
(660 ft.)
[redacted]
UltraScan CD
Water
Batching pigs
Air
b)
Direction of inspection
500 m
(1600 ft.)
200 m
(660 ft.)
Pumping
Slide 9


TEMPORARY LAUNCHER & RECEIVER
April 9-12, 2001
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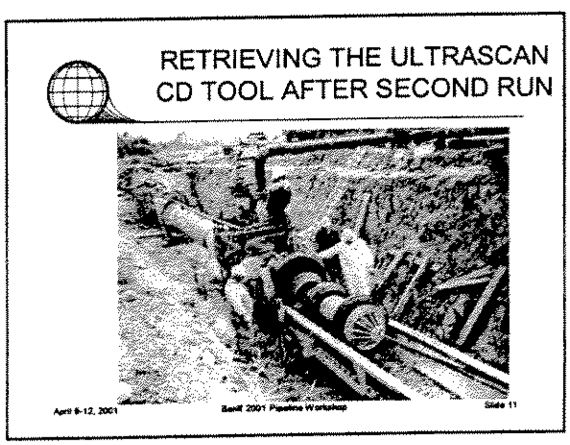
Slide 10


RETRIEVING THE ULTRASCAN CD TOOL AFTER SECOND RUN
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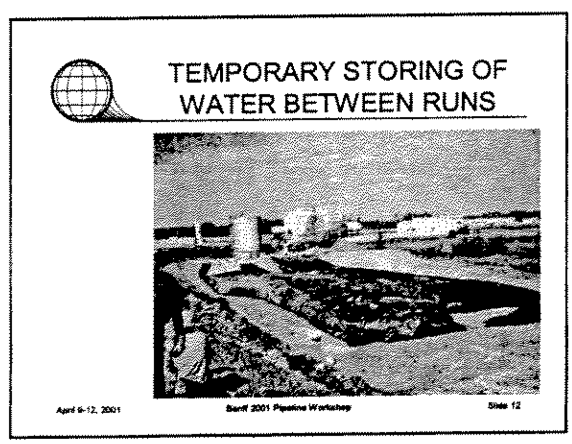
TEMPORARY STORING OF WATER BETWEEN RUNS
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SPEED PROFILE FOR 62-63-2 AND 92-93-2 ULTRASCAN CD RUNS

- These two UltraScan CD tool runs using the previous procedure were very smooth.
- The Average inspection speeds were:
  - 0.28 m/s for the water pumped directions, and
  - 0.245 m/s for the air compressor driven dewatering runs in the opposite directions.

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REPRODUCIBILITY OF INSPECTION

[redacted]

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REPRODUCIBILITY OF INSPECTION

- Not a single defects (cracks, crack fields) with an estimated depth > 12.5 % W.T. (i.e., 1 mm) was missed in the corresponding reversed (second) run
- Lengths and depth classification from both runs were good:
  - with a mean deviation in length: ± 8% and ± 7% for the two inspected sections
  - with depths in the same depth categories as measured in 82% of the defects measured in one section, and 92% of the defects measured in the other section

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ACCURACY OF FEATURE DEPTH AND LENGTH PREDICTIONS

[redacted]

[redacted]

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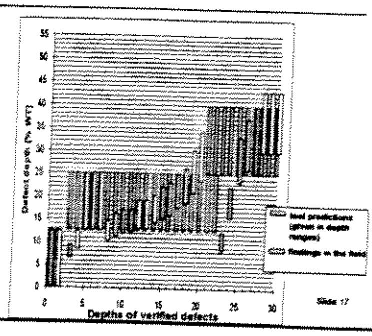
ACCURACY OF FEATURE DEPTH AND LENGTH PREDICTIONS



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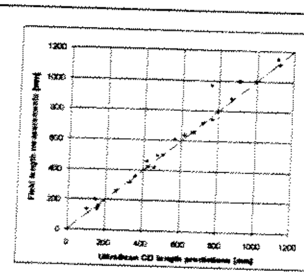
ACCURACY OF FEATURE DEPTH AND LENGTH PREDICTIONS

Defect lengths predicted by the ILI tool vs. measured in the field



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CONCLUSIONS OF RECENT ULTRASCAN CD R&D

- It is possible to inspect a gas pipeline using the UltraScan CD tool in a liquid slug
  - proper preparations are important
- UltraScan CD tool has sufficient sensitivity and discrimination for finding and accurately sizing SCC for integrity management purposes
- a "base-line standard" has been established for measuring the performance of new crack detection tool against
- Assessment of CD tool data would be enhanced if Effective Area Assessment methods for calculating remaining strength were possible.

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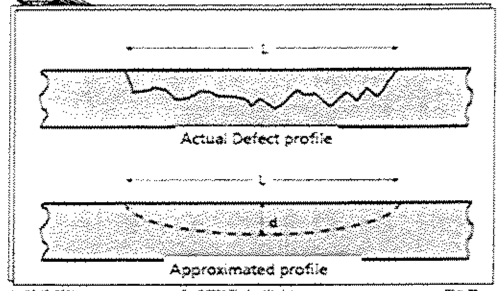
EFFECTIVE AREA REPRESENTATION



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EMATSCAN CD TOOL DEVELOPMENT - TIMELINE

1997 Pipetronix proposed new EmatScan CD Tool concept for Gas Pipelines

1998 TransCanada, IzfP and Pipetronix complete Technical Feasibility Study of EmatScan CD Tool Concept

1999 PII and Pipetronix merge & Agreement for Developing a EmatScan CD Tool negotiated

2000 Tool Design Finalized

2002 Acceptance Testing of Tool planned

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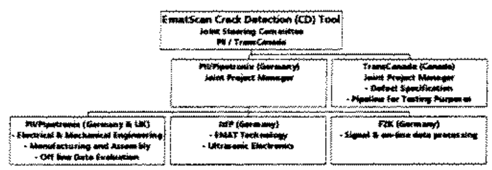
PROJECT PARTNERS

- Financial Support from each partner
- Project jointly steered by PII and TransCanada
- Organization chart for Project is as follows:



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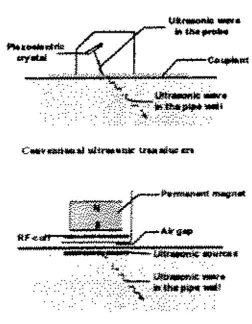
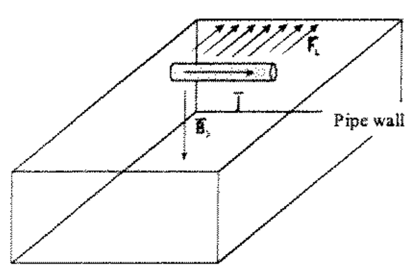
PRINCIPLE OF OPERATION

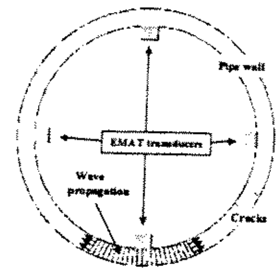


BASIC PRINCIPLE OF OPERATION OF EMATS



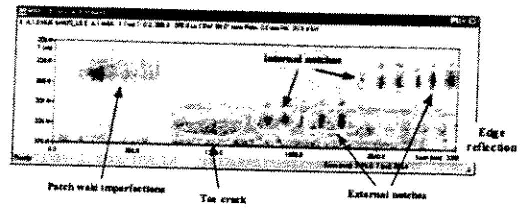
Basic principle of operation of EMATs

EMATS FOR DETECTION OF CRACKS IN PIPE WALL



EMATs for detection of external and internal cracks and crack-like defects in the pipe wall

EXAMPLE OF DATA FROM A EMAT CRACK SENSOR ILLUSTRATING REFLECTIONS FROM DIFFERENT TYPES OF FEATURES



B-scan made with an EMAT transducer illustrating detected reflections and the corresponding defects

CHARACTERISTICS OF EMATSCAN CD

- The goal of the new EmatScan CD tool are to:
  - be able to operate in gas lines without a liquid couplant
  - be a robust and reliable design
  - provide full circumference wall coverage
  - provide redundant detection of sub critical SCC features
  - discriminate between internal and external features
  - determine the length and depth of axial crack features
  - predict effective areas, if possible

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TOOL DEVELOPMENT AND RESEARCH

- Questions?

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Workshop Session 8 - In-line Inspection of Transmission Pipelines
Wednesday, April 11, 2001 at 8:30 a.m. – noon

Co-Chair: Steve Gosse, Westcoast Energy
Co-Chair: Arti Bhatia, Alliance Pipeline
Poll Compilation – Blaine Ashworth, TransCanada PipeLines

Results of workshop poll on what the next Key Research and Technological Advancements the pipeline industry will need in next 5 years.

Pipeline Operators

- Crack Detection (SCC) & sizing (Gas Line)

- Increased tool reliability (hardware)

- Improvements on CD Tools for Distinguishing different defects and terminology clarification
  - Mechanical Damage – incl. orientation on caliper
  - Higher Accuracy –small diameter internal pits
  - Crack Detection
  - Increased Focus on ILI Repeatability – Reporting

- Smaller diameter (i.e.,) down to 6" and 8" reliable crack detection tool

- Crack detection & discrimination tool
  - More accurate defect measurement for general corrosion
  - Automated external corrosion validation tool

- Competition for UT tools (get prices in-line
  - A tool that will grade severity of weld defects

- Better Reporting Accuracy
  - "Multi-Purpose" tools – all-in one
  - Pressure Failure Predictions for all types of defects

- Tool Measurement standardization – sounds logical, probably normal in other industries
  - Maybe there needs to be several "test" or "validation " pipe sections around continent that serve as baseline references to normalize between variables (tool type, operator, etc.) Vendor would certify recent validation before use.

- Multi defect identification with a single tool/ single run. (I.e., crack, corrosion, geometry & corrosion (or ideally all).
  - Algorithm development (continued) for faster, more accurate data reporting.

  - Possibly a more defined set of standards or guidelines for vendors to follow in building and operating ILI tools.

- Develop a "compact" low powered tool (i.e., digital or laser) that will have redundant measurement in the same train to validate data.
  - Tools that will draw the pipeline profile and provide an image of every feature, dent, transition, etc. (i.e., like an internal camera). This tool should have the same accuracy for different speeds.

Others

- Reliable Detection of Seam Weld defects no ERW pipe in small sizes down to 6"

- UT corrosion detection & sizing for gas pipelines able to run in gas or oil.

- Better 1st run reliability
  - Detection & sizing of longitudinal cracks in gas lines
  - Inspection at higher gas flows
  - Repeatable results
  - Better accuracy of sizing

- Improvements are needed for geometry survey & feature definitions & definition & investigations. Prime focus should be verification for safety evaluations, maintenance time prediction for reliabilities. Integrate Materials & ultrasonic CD approaches good reasons, may become the best approach.
  - Pipe Movement monitoring is more viable than Stress monitoring. I believe this enhancement will be made.

- Standardization of terminology of terminology and reporting for ILI runs. We can talk about Probability of Detection until the Cows come home but is everyone (operator s, inspection companies/ regulators) an example, measuring a defect differently, and then we will never achieve the ultimate capability of using these tools!
  - Better MFL for very thick walled pipe – Arctic applications
  - Real time Risk assessment /Risk Management from ILI data

- Standardization including terms, accuracy & sizing, analysis, etc.
  - Pipe in Pipe inspection
  - Better define dents & damage (stress concentration, etc.
  - Improve repeatability of inspections
  - Improve accuracy of sizing defects
  - Work towards inspecting low pressure gas pipelines

- Be able to identify mechanical damage better.
  - Be able to size cracks more consistently

- Multiple Technologies on one ILI Tool, to enhance detection and accuracy, also providing greater value to the operators

- To see the increasing development and use of EMAT technology.

- Stress corrosion cracking tool.
  - Caliper & MFL tool combination.

- 10/12" Ultrasonic crack detection tools
  - Mechanical damage characteristics too
  - New ultrasonic crack detection tools for gas lines

- Combination of technologies to consolidate crack, wall loss and deformation in one survey.
  - This is needed now to address the rising concern in 3rd party damage, which requires all three technologies to fully identify and quantify.

- Inspect the interior pipe of a steel pipe in steel pipe system. It is a liquid pipeline. The interior pipe is not concentric or in a consistent location within the outer pipe. Inner pipe is 10" x 0.688 WT, the outer pipe is 12" x 0.75" WT. Annular space in filled with inert gas. Operating temperature is 150F operating pressure 1600 psia.

- Real Time Readings from free swimming tools
  - On board comparison of inspections logs while tool is running
  - Bi-directional capabilities for large diameter transmission pipelines
  - The ability to determine if a run is good within a few hours.

Managing Pipeline Integrity: In-Line Inspection of Transmission Pipelines
April 11, 2001 8:30 a.m. - 12:00 p.m.

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Managing Pipeline Integrity: In-Line Inspection of Transmission Pipelines
April 11, 2001 8:30 a.m. - 12:00 p.m.

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Managing Pipeline Integrity: In-Line Inspection of Transmission Pipelines
April 11, 2001 8:30 a.m. - 12:00 p.m.

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BANFF/2001 PIPELINE WORKSHOP

Working Group 8: In-line Inspection of Transmission Pipelines

April 9-12, 2001 Banff 2001 Pipeline Workshop

Introduction

- Working Group 8: In-line Inspection of Transmission Pipelines
- Topics - State of the Industry, Mechanical Damage, Dent Assessment, Tool Validation and R&D
- ILI Vendor, Operator, Regulators and Consultants

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Today's Discussion

- State of the Industry Today - Harvey Haines (GTI)
- Inspecting for mechanical damage, dents, hard spots - Bruce Nestleroth (Batelle), Blair Carroll (Fleet Technology)
- Vendor Tool Performance Specifications - Tom Morrison (Morrison Scientific)
- R&D - Blaine Ashworth (TransCanada Pipelines)
- Industry Standards - Reena Sahney (TransCanada Pipelines)

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1999 Discussion

- Tool development
- False Calls
- Feedback to vendors/vendor involvement
- Levels of analysis
- Circ MFL
- User's Groups
- Industry Standards for tools specs, accuracy, confidence levels and terminology

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2001 Objectives

- ILI Tool Technology Advancements
- Continue the dialogue with all stakeholders
- Defect Models, Tool Validation
- R & D

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What was discussed

- Recognition of new advances in technology for mechanical damage, high resolution and crack detection
- Recognition that standard formats need to be used in areas such as defect sizing capabilities (POF Format), defect terminology (NACE Standards, CSA - sharp dents, gouges, "cracks", multi-mode defects)
- Data gathering protocols and information feedback to vendor is the key to most successful ILI runs
- Three wishes survey

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What still needs to be done

- Groups and consensus to come together on standardization of terminology
- Groups and consensus for validation of various configurations of defects
- CEPA, NACE, API, OPS initiatives, CSA, ad-hoc committees need to have continued communication across their levels to ensure the standards and consistency
- Vendors need to be part of these groups and consensus so that different levels do not exist.

April 8-12, 2001 Banff 2001 Pipeline Workshop

Working Group 9: Risk Assessment: Communication, Public Consultation and Planning

Tuesday, April 10, 2001, at 3:30 p.m.

Chairman: Ray Smith

Presentation Summary

This working group started with a National Film Board video entitled, "Worst Case Scenario". This video presented the diversified viewpoints of industry, the regulator, and the public - on the drilling of a sour gas well. The video narrated the story on how a project of drilling a sour gas well did not move forward, in spite of the fact that the company had both surface and sub-surface permission, but not the community support. The video also highlighted the need for more communication between the industry and the public; how to consult the public; and tips to plan new projects.

The discussions that followed the video are as follows:
Ian Dowsett pointed out that the issue of public perception keeps coming up in this Workshop and it is necessary to advance this issue.

Industry should move from the "reactive" mode to the "advance planning" mode with respect to public consultation.

Bill Tyson inquired, "what is the risk of this particular well when it is compared to other wells"? Ian Dowsett informed the attendees that this particular well was classified as Level 4 and the risk can be considered as acceptable.

With respect to the particular case presented in the video, one of the principal issues was that the company wanted to reduce the emergency response zone to 4 km, as opposed to the normal 12 km.

The difference in the perception between the industry and the public was explained. For example, the industry generally performs a risk analysis and arrives at a number. This risk number is then compared with a published standard, e.g., MIACC. On the other hand, the public does not care for the numeric risk values. This makes the communication between the industry and public more important.

The time lag between the leak and risk is about 1 - 6 hours if the leak occurs in a well, but there is no time lag if the leak occurs on an operating pipeline.

Ian Scott presented some tips on how a company should move forward with a project.

- Conduct good homework. Consult with the public at a very early stage. Give options to the public. Provide room and prepare to modify the project.

Art Meyer also shared the view, and further indicated, that the public should be fully engaged; the project should be communicated properly; alternatives identified; and appropriate changes should be accommodated in the project.

Important points to be noted in communication:

- The Public should not get the impression they are dealing with PhD's and experts are being brought in to force them to change.
- Prepare to accommodate public view and needs.
- Provide options and alternatives.
- Build credibility and trust.
- Negotiation requires values.
- Identify the person to communicate.

Various forms of communications methods were discussed, as follows:

- Informal is better, stay out of adversarial issues.
- An inquiry is not necessarily the best option.
- Field operators provide the first contact with the public and should be better prepared to communicate with the public. They should be trained to communicate appropriately.
- Too much communication should be avoided. For example, if 4-5 companies are drilling in a community, and if they all communicating with the public on same issue, the public will be lost in the information overload.
- One contact rather than multiple contacts.

It was highlighted that more than 50% of the companies are not part of any association, (e.g., CAPP) and are not part of any industry discussions.

Ian Scott informed the attendees about the public consultation process that CAPP is undertaking.

With respect to the public communication:

- The issues are important, not numbers.
- Values are more important than facts.
- The regulator, (e.g., AEUB), moves in the direction in which the companies become more responsible (self audit).
- There is a process in place in which the corporations are ranked and the non-performers are punished rather than the whole industry.
- There should be an industry bench mark.

Recommendation: A coordinated effort to develop a "Risk Communication Tool"

BANFF/2001 PIPELINE WORKSHOP

Risk Assessment / Risk Management: Communications, Public Consultation, Planning

Ian Dowsett, RWDI West Inc.

April 9-12, 2001 Banff 2001 Pipeline Workshop

Program Agenda

Video "Worst Case Scenario"
Discussion
Recommendations

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Roles and Responsibilities: Industry

Industry is responsible for the risks and for managing these risks.

- Individual companies (due diligence)
- Industry organizations and associations e.g. CAPP, CCPA

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Roles and Responsibilities: The Regulator

The regulator holds the responsibility for facilitating decision-making, the decision itself, and for ensuring that agreed-upon provisions (designed to address the risks) are met. (e.g. NEB, AEUB, US EPA)

- Incentives and disincentives
- Acts and regulations
- Standards and guidelines

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The Role of the Public

The public does not have a direct responsibility; they have a role in understanding the issues and being involved in the process.

- Individual involvement
- Organizations and activities

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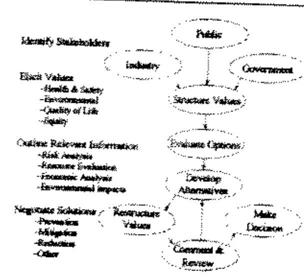
Public Involvement Process



April 9-12, 2001 Banff 2001 Pipeline Workshop

Managing Pipeline Integrity: Risk Assessment/Risk Management: Communications, Public Consultation, Planning
April 10, 2001 3:30 p.m. - 5:00 p.m.

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Managing Pipeline Integrity: Risk Assessment/Risk Management: Communications, Public Consultation, Planning
April 10, 2001 3:30 p.m. - 5:00 p.m.

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BANFF/2001 PIPELINE WORKSHOP

Risk Assessment / Risk Management: Communications, Public Consultation, & Planning

Ian Dowsett, RWDI West Inc.

Group 9 Recommendations - Part 1

- Move from adversarial to consultative processes: i.e., consultation versus hearings.
- Understand the hazards and risks earlier in the process; i.e., ensure that we communicate the right message.
- Distinguish between risk communications techniques and risk communications processes.

Group 9 Recommendations - Part 2

- Field staff provide the first contact with the public; they should be trained in risk communication techniques.
- The public are increasingly being contacted about energy development; efforts should be made to deliver the correct message and reduce the number of visits.

Group 9 Recommendations - Part 3

- Issues are more important than numbers: i.e., an annual risk of fatality of 1.0E-06 has no meaning to the public, they will only hear the word fatality.
- Understand the issues and concerns expressed by the public and incorporate these into the design of and operation of the system.

Working Group 10 - EXTERNAL CORROSION

Tuesday, April 10, 2001 at 10:30 a.m. – 5:00 p.m.

Co-Chair: Robert Worthingham, TransCanada Pipelines
Co-Chair: Trevor Place, Corrosion Service
Rapporteur: Coral Lukaniuk, Global Thermoelectric

Summary from Banff/1999 Pipeline Workshop

This working group was focused on monitoring, assessing and predicting external corrosion. Approximately, 55 participants attended the first session on Remaining Strength and approximately, 85 participants attended the session on Corrosion Growth.

For Remaining Strength Assessment, the working group agreed that more direction in CSA Z662 would be helpful. The CSA Subcommittee would consider including a reference to RSTRENG using a "commentary". The CSA Subcommittee has included a reference of RSTRENG in the latest draft. Also, over 80% of the attendees indicated that training in remaining strength assessment would be beneficial. Based on this, it was recommended to CEPA to organize a 3rd party training program. This has occurred as part of this.

For Corrosion Growth, the working group was going to discuss with the CEPA the possibility of preparing a standard guideline for field measurement of corrosion damage. Similarly, the working group was going to discuss with the CEPA the possibility of using the CEPA Database for collecting soil analysis and associated corrosion rate information. The suggestions are currently being reviewed by CEPA.

10.1 Environmental Impact of Groundbeds

Katherine Ikeda-Cameron, NRTC & Tom Jack, NRTC

Objectives

10.1.1 Review recent investigations into environmental impact of impressed current groundbeds (NRTC research).

10.1.2 Understand possible ramifications to the corrosion control industry.

Questions & Discussion

1. Dave Hektner, BJ Pipeline Inspection Services – How deep is an anode bed. Grant Firth, Corrpro Canada – Approx. 100m.
2. Jamie Cox, DuPont Canada – Is temp an issue? Tom Jack, NRTC – Different electrochemical reactions may depend on temperature.
3. Doug Waslen, NEB – Are they moving back towards graphite anodes?

4. Bob Gummow, Correng Consulting – There is coke around the anode and the oxidation reaction is around the coke. Maybe we need more carbon backfill or to run the beds at a lower current density (higher pH). Tom Jack, NRTC – many of the studies were around petroleum coke.
5. Stan Wong, CC Technologies – Any problems with aquifers mixing? Peter Haas, Corrpro Canada - Some problems and in some cases, had to modify the groundbeds.
6. Grant Firth, Corrpro Canada – One of the clients is more concerned with surface water getting into the well bore. Any thoughts on contamination with shallow groundbeds as oppose to deep beds? Trevor Place, Corrosion Service – Was there a difference between the two? Tom Jack, NRTC – Have some data on the shallow beds and have noticed some contamination within a meter of the anodes. It quickly diminishes to background levels. All studies for deep anode beds have been based on spit up water.
7. David Jolivette, Canspec – Any data on the beds before they went into place? Grant Firth, Corrpro Canada – Most clients do not complete an analysis but soil resistivity is measured. Are there similarities in the soils? Doug Waslen, NEB – There is a lack of understanding/ sharing in the industry but it has come a long ways. It is much better to share info.
8. Bob Gummow, Correng Consulting – Types of contamination. Tom Jack, NRTC – Guidelines seem to be applicable for the hexavalent chromium. Hexavalent chromium is strongly dependent on the pH.
9. Reg Eadie, NRTC - What are guidelines for, shallow or deep beds? Doug – Not at this time. It makes sense to treat the deeps as water wells.
10. Cliff Mitchell, CJ Mitchell & Associates – High concentration around the anode? Tom Jack, NRTC – The exceedances are not very high and often within experimental error.
11. Tom Jack, NRTC – Would the roots of crops mobilize these metals? Robert Worthingham, TransCanada – There doesn't seem to be a strong concern but will keep Alberta Environmental Branch informed of future studies.
12. Cliff Mitchell, CJ Mitchell & Associates – Alfa and clover are very deep. Tom Jack, NRTC – confirmed that clover has deep roots and it is common to find them at 2m (shallow bed).
13. Peter Haas, Corrpro Canada – That beds that have spit up have occurred in areas where there is a high water table. Most simple solution seems to be to run a higher standpipe.
14. Tom Jack, NRTC – Commented that some of pressure in the standpipe has reached as high as 10psi.
15. Vote – Deep beds spit up.
    Totals: 23 consultants, 9 researchers, 3 regulators, 7 downstream, 2 upstream
    a. Is this a problem? YES - 10 consultants, 4 researchers, 3 regulators, 2 downstream, 0 upstream
    b. Should more work be done? YES - 19 consultants, 7 researchers, 3 regulators, 6 downstream, 1upstream
    c. Do we need more communication? YES - 14 consultants, 7 researchers, 3 regulators, 5 downstream, 2 upstream
16. Cliff Mitchell, CJ Mitchell & Associates – From the research, shouldn't there be recommendations to use materials that produce the least amount of contamination? Trevor Place, Corrosion Service – We need a balance. Doug Waslen, NEB – What's the tolerable level of risk? Robert Worthingham, TransCanada – We should work more closely with the regulating bodies. Water and soil guidelines for contamination exist. Tom Jack, NRTC – This is an argument for compliance. Reg Eadie, NRTC – Some work has been done but

maybe not enough to put forth recommendations. Robert Worthingham, TransCanada – TransCanada is currently looking at a number of sites.

17. Grant Firth, Corrpro Canada – Is fluid "spit-up" from deep beds just a problem in AB? Peter Haas, Corrpro Canada – Confirms that he has seen it throughout the province. Robert Worthingham, TransCanada – Does anyone uses deep beds outside of AB? Bob Gummow, Correng Consulting – Hasn't seen any evidence in Ontario but believes more work needs to be done.
18. John Chase – Hunter McDonnell Pipeline Services – Who funds the research? Robert Worthingham, TransCanada – TC has funded this to get an understanding of the situation. Maybe we can suggest to CEPA to do more work.
19. Peter Haas, Corrpro Canada – Believes it is easy to quantative the amount of chemicals in the soil. Believes the contamination is very low and therefore, it is not a problem.
20. Tom Weber, Trenton Corp. – NACE would be a good source to form a task group to study this. Robert Worthingham, TransCanada – There is some discussion on the NACE web page.

10.2 Review of Cathodic Protection Codes & Standards

R.A. Gummow, CORRENG Consulting Service Inc.

Objectives

10.2.1 Review of industry codes and practices governing CP.
10.2.2 Explore differences in code interpretation and code intention.
10.2.3 Determine if codes and standards adequately address the intention of asset management.
10.2.4 Review accepted cathodic protection criteria and developments in monitoring technologies intended to satisfy protection criteria.
10.2.5 Explore difficulties in assessing CP criteria conformance (interpretation and application).

Questions & Discussion

1. Barry Martens, Rainbow Pipeline – We had more difficulty achieving –850mV criteria than the 100mV criteria under tanks.
2. Bob Gummow, Correng Consulting – Is it more economical to use 100mV?
3. Grant Firth, Corrpro Canada – Shouldn't the criteria be set by science and not owners? Bob Gummow, Correng Consulting – This is just a position.
4. Barry Martens, Rainbow Pipeline – More choices are maybe better. Bob Gummow, Correng Consulting – The criterion do not give you zero corrosion.
5. Doug Waslen, NEB – Would the 100mV criteria achieve the minimum to avoid SCC? Bob Gummow, Correng Consulting – Need to beware of sensitive areas.
6. Bob Gummow, Correng Consulting - Reference to OCC-1-1996, Section B.2.5. How many people change their criteria based on these "other considerations"? Robert Worthingham, TransCanada – Confirmed that TransCanada does.
7. Vote – CP Criteria

   Total of 34 attendees that are users.

   a. –850mV off? YES – 53%
   b. 100mV polarization? YES – 35%
   c. Other? YES – 12%

8. Doug Waslen, NEB – If you're not following industry practices, then you should document why you are not.
9. Bob Gummow, Correng Consulting – Do you use more rigorous criteria downstream of compressor stations?
10. Bob Gummow, Correng Consulting – With time, we're going to see less provincial and national standards and more international standards.
11. Robert Worthingham, TransCanada – How many people are using coupons? 3
12. Doug Waslen, NEB – Reiterated Bob Gummow's comment that Canadian situations are unique. Doesn't think NACE standards are fully accepted in Canada.
13. Bob Gummow, Correng Consulting – Is -950mv an imposition?
14. Trevor Place, Corrosion Service – Do the upstream companies simply work with prescriptive guidelines? Doug Waslen, NEB – The industry wants both prescriptive and goal oriented regulations and it is very difficult to know the best path. It is difficult to audit. Alex Petrusev, Corrosion Service – Why is it difficult? Don't you require seeing that a company is meeting the benchmarks? Doug Waslen, NEB – Many companies meet the criteria but could still have corrosion.
15. Reg Eadie, NRTC – As a member of the public, I wouldn't be happy with 100mV if other companies are doing more. We need adequate protection to protect the public.
16. Barry Martens, Rainbow Pipeline – If you had a leak, how do you determine what is adequate? Doug Waslen, NEB – It depends on the situation, e.g. tape applied coating that shields the CP. Can't take one issue and dictate your corrosion program.
17. Robert Worthingham, TransCanada – I encourage you to get involved with CSA and CGA to avoid future surprises.
18. Tom Morrison, Morrison Scientific – Mentioned that NACE was encouraging the move towards to 100mV based on the info at the NACE National… ~4 papers.
19. Alex Petrusev, Corrosion Service – Why discount the -850mV criteria? John Beavers, CC Technologies – 100mV proves to be more beneficial for many companies that cannot achieve the 850mV. Doesn't think NACE will drop the -850mV as the 100mV takes extra work. Bob Gummow, Correng Consulting – The 100mV doesn't appear in any of the world standards.
20. Barry Martens, Rainbow Pipeline – Checked for CP by using a holiday detector on a tape-coated line. Wherever, it jeeped, SCC wasn't detected.
21. Tom Weber, Trenton Corp. – Has anyone found SCC under other types of coatings? Doug Waslen, NEB – yes, asphalt. Offered the SCC report. John Beavers, CC Technologies – It is more likely to find it under tape but will find it under asphalt. Made a reference to finding SCC under swamp weights. For high pH SCC to occur, need high CP levels.
22. Alex Petrusev, Corrosion Service – What about seasonal variations and how it affects the criteria? Bob Gummow, Correng Consulting – Some companies monitor these situations. Doug Waslen, NEB – Isn't TransCanada doing some work on seasonal CP? Robert Worthingham, TransCanada – yes. Greg VanBoven, NRTC – Resistance goes down in spring and goes up in the summer. In the winter, the resistance may be more electro-negative. Dry soils are a concern as there are more fluctuations.
23. Tom Jack, NRTC – Criteria are general rules but do not necessarily achieve the end result of corrosion protection. If the object is to protect the pipe, how relevant are the criteria in 100000 ohm-cm soils? How much influence, would this have in a dry environment?

24. Mark Johnson, Marr Associates – The criteria assists with both general corrosion and SCC so we need criteria.
25. Cliff Mitchell, CJ Mitchell & Associates – How do you know the pipe is protected? Dig it up to prove it?

    Aside: Many of the comments refer to the overhead slide on German criteria, which is based on operating temperature and soil resistance, for unalloyed and low-alloy ferrous materials.
26. Greg VanBoven, NRTC – 100mv is almost impossible to prove, as the soil is not homogenous. This hard to prove. Germans are looking at things they can measure on the surface. Likes what the Germans are saying.
27. John Beavers, CC Technologies – Highlighted that all the existing criteria measures the average around the pipe, not just the 100mV criteria. Non-homogenous soil affects all criteria.

    Aside: Turn off sufficient cp current sources that influence the pipe at the test site until at least 100mV cp polarization decay... (10.2.5.7.1) (overhead slide)
28. Robert Worthingham, TransCanada – How do the regulators feel about pipelines being unprotected while depolarized surveys are being performed to confirm alternate criteria is being met? Doug Waslen, NEB – The regulator is not going to say what to do and what not to do but it is up to the industry to follow their own programs
29. Bob Gummow, Correng Consulting – Isn't the cracking range and the 100mV criteria in conflict? John Beavers, CC Technologies – Care must be taken to ensure the pipe is not inside the SCC cracking range when applying the 100mV criteria.
30. Tom Jack, NRTC – an unprotected pipeline proved to be quite a challenge to bring up the CP levels after a long absence of protection.
31. Robert Worthingham, TransCanada – What length of time is required for depolarization to occur? Alex Petrusev, Corrosion Service – Relied on the field personnel to inform him of the length a time needed to depolarize. Each area was unique. Bob Gummow, Correng Consulting – There isn't a consensus on how long to leave it off. Some people suggest using a coupon as a way to assess the protection. Doug Waslen, NEB – As long as the coupon is a representation of a pipe. Bob Gummow, Correng Consulting – A coupon is more like a holiday on the pipe.
32. Reg Eadie, NRTC – What about temp? Is the coupon the same temp as the pipeline? Bob Gummow, Correng Consulting – Not always.
33. Bob Gummow, Correng Consulting – Do you find coupons expensive? We need to think of the long-term savings.
34. Alex Petrusev, Corrosion Service – What is the savings by using the 100mV? Bob Gummow, Correng Consulting – Most companies only use the 100mV criteria if 850mV could not be met.
35. Bob Gummow, Correng Consulting – The standards would most likely avoid specifying where to put coupons. Coupon use wouldn't be necessary if you were meeting the 850mV criteria.
36. Bob Gummow, Correng Consulting – Reference to NACE Test Method TM0497-97 – Use of Coupons to Determine the Adequacy of Cathodic Protection
37. Doug Waslen, NEB – How do you know if coupons represent the pipe? Peter Haas – It was accepted for Alyeska. John Beavers, CC Technologies – There was zinc ribbon along the whole line. CC did some modelling work to demonstrate the effectiveness.

38. David Jolivette, Canspec – Are pipe depth CP readings taken at excavations being used? Robert Worthingham, TransCanada – TransCanada is collecting info (soils data, ILI data, etc.) in a database to assist with CP system.
39. Barry Martens, Rainbow Pipeline – Commented that current is going through the coatings but you need to check.
40. John Chase, Hunter McDonnell – Is the CP data being correlated to the ILI data? Robert Worthingham, TransCanada – It is difficult to correlate the data. Care must be taken when determining what the correlations mean.

10.3 Corrosion Field Measurement and Growth Modeling

Objectives

10.3.1 Review recent field validation of corrosion growth models.
10.3.2 Determine application and limitations of corrosion growth models.
10.3.3 Discuss recent developments in external corrosion mapping techniques.

10.3a Corrosion Rate and Severity Results from In-Line-Inspection Data

Guy Desjardins, Morrison Scientific

Questions & Discussion

1. Brad Smith, Enbridge – How do we keep tack of variable growth rates? Guy Desjardins, Morrison Scientific – There are seasonal changes and therefore, some variability. Brad Smith, Enbridge – Is corrosion growth linear?
2. Fraser King, NRTC – Do you take into account that changes may occur yearly – between inspections? Guy Desjardins, Morrison Scientific – Yes. There is not much difference in rates. Growth was a few percent per inspection.
3. Bruce Dupuis, Baseline Technologies –Was MIC involved in the data sets considered? Robert Worthingham, TransCanada – yes. Guy Desjardins, Morrison Scientific – Some cases there were shallow features and others were deep. All features were included.
4. Stan Wong, CC Technologies – Growth size and accuracy. Guy Desjardins, Morrison Scientific – Used ILI data and compared it to field data. Found that it is within the 10%.
5. Greg VanBoven, NRTC – Is it valid to overlay CP data over time to validate if CP is related to disbonded coatings? Tom Morrison, Morrison Scientific – Can be done. Greg VanBoven, NRTC – There would be benefit. Tom Morrison, Morrison Scientific – Depends on the CIS data accuracy.
6. Doug Waslen, NEB – This type of analysis is very worthwhile as it helps companies to defend their position.
7. Doug Waslen, NEB – In the US the ILI frequency intervals are very arbitrary.
8. Barry Martens, Rainbow Pipeline – Did you achieve what you wanted to? Robert Worthingham, TransCanada – TransCanada was able to extend there interval period form 4 to 6 years on one line.
9. Stan Wong, CC Technologies – Regarding the error banding, the model doesn't seem to follow a linear pattern. Robert Worthingham, TransCanada – The acceptable risk is up to the company, which is handled outside of the prediction model. The prediction can aid in potentially high-risk areas.

10. David Jolivette, Canspec – How accurate are the predictions? Guy Desjardins, Morrison Scientific – Calculate probability of failure, etc for features along the pipeline. David Jolivette, Canspec – How is soil incorporated in the predictions? Robert Worthingham, TransCanada – The soil data helps to prioritize pipelines for their first inspections.
11. Harvey Haines, Gas Technology Institute – Have these been compared to the British Gas results? Robert Worthingham, TransCanada – PII is looking at the raw inspections to see if there is a change. Must be done with two PII data sets. As long as the data, from repeated inspections, is in a similar format, various sets of data can be reviewed with the Morrison Methodology. This is independent of the ILI tool used.
12. Harvey Haines, Gas Technology Institute – Direct assessment in the US… can the data be shared with some of the companies in the US? Robert Worthingham, TransCanada – We could consider this depending on the type of data they are looking for.
13. Barry Martens, Rainbow Pipeline – We really need to understand and be confident of the data you receive from the ILI vendor.
14. Ivani de S. Bott, Catholic University of Rio de Janeiro– What about the compositions? Can you use the prediction on other pipeline? Robert Worthingham, TransCanada – The composition and rate are applied per site. It is being investigated and has been applied with some success.
15. Vote – How many want to see more updates? ~50% of attendees

10.3b Laser-Based Corrosion Mapping System for Pipelines
Richard Kania, RTD Quality Services Inc.

Questions & Discussion

1. Trevor MacFarlane, Dynamic Risk – Feels this what the industry needs. The burst pressure is determined by remaining metal. Is there anything that RTD does to account for coincident small scale bulging, which may result in a non-conservative assessment? Richard Kania, RTD Quality Services – We've developed software to overcome some of the problems. The data is marked circumferentially. Each line is assessed independently. By doing this, we can see the deformations. We use a pencil probe to verify the remaining wall thickness is as expected.
2. Reg Eadie, NRTC – Methods using people vs. automation. For example, a human will see crud but the machine won't. Richard Kania, RTD Quality Services – The surface has to be clean otherwise, the mapping results will be inaccurate. Tool operator checks cleanliness.
3. Kyle Keith, Foothills Pipelines – Foothills has used the tool and has found it beneficial. Richard Kania, RTD Quality Services – In the future, would like to measure the pipe without having a cleaned surface.
4. Dave Katz, Williams Pipeline West – Would like to see something like this in the US. Is the tool used mostly to map complicated corrosion areas? Kyle Keith, Foothills Pipelines – It saves the most money when it can be used for a long section.
5. Robert Worthingham, TransCanada – The faster you can get in and out of a repair site, the more money is saved as the crews who are on stand-by can take the next steps. The quality of info is very good and you get a much better feel of what is really there.

6. Harvey Haines, Gas Technology Institute – Are you sharing your data with vendors? Robert Worthingham, TransCanada – Yes.

Possible Topics for 2003

- Comparison of ILI data with above ground techniques.
- Latest developments on CP criteria – NACE, CSA, CGA
- Internal Corrosion Experience in Transmission Pipelines – monitoring & mitigation
- Correlation of GIS data sets – ILI, soil, etc.
- Soil models for predicting corrosion.
- Update of the environmental impact due to groundbeds.

BANFF/2001
PIPELINE WORKSHOP

Working Group 10: External Corrosion

Bob Worthingham: TransCanada
Trevor Place: Corrosion Service

WG 10: External Corrosion

- Have Fun
- Learn from each other
- Share experiences

Action Items From 1999 WG

- Objective: Determine if CSA should be revised to explicitly reference RSTRENG. Explicit references decrease the flexibility and life of a standard; however, the group recognizes that more direction in CSA Z662 would be helpful.
- Action: The CSA Subcommittee consider including a reference to RSTRENG using a "Commentary".
- Status: The CSA Subcommittee has included a reference to RSTRENG in the latest draft.

Action Items From 1999 WG

- Objective: Determine if training in remaining strength assessment is required. Over 80% of attendees indicated they would find such training beneficial.
- Action: Working Group Co-Chairs will recommend CEPA arrange a 3rd party training program to be rolled out in late 1999/2000.
- Status: This has occurred.

Action Items From 1999 WG

- Objective: Explore advances of direct and indirect corrosion growth monitoring methods.
  - Determination of site-specific corrosion rates have been demonstrated and used in planning maintenance.
- Action: Working Group Co-Chairs to discuss with CEPA the possibility of preparing a standard guideline for field measurement of corrosion damage.
- Status: Database is under revision. Suggestion will be considered.

Action Items From 1999 WG

- Objective: Explore advances of direct and indirect corrosion growth monitoring methods.
  - Soil coupons are an alternative in locations where ILI data are difficult to obtain. Concern was expressed on how to analyze and characterize soils for corrosion rate correlations
- Action: Working Group Co-Chairs to discuss with CEPA the possibility of using the CEPA Database for collecting soil analysis and associated corrosion rate information.
- Status: Database is under revision. Suggestion will be considered.

Objectives

- Have Fun
- Learn from each other
- Share experiences

April 8-12, 2001 Banff 2001 Pipeline Workshop Slide 7

Environmental Impact of Impressed Current CP Groundbeds

- The significance of soil contamination caused by impressed current groundbed operation
- Possible ramifications to the corrosion control industry

10:30 - 12:00

April 8-12, 2001 Banff 2001 Pipeline Workshop Slide 8

Codes and Practices Relating to Cathodic Protection

- Regulations and non-regulatory guidelines
  - CSA Z662, OCC-1, NACE RP-0169, Canadian Electrical Code, CSA C.22.3 No. 6, NACE RP-0177
- Differences in code interpretation and code intention.
- Accepted CP criteria and developments in monitoring technologies intended to satisfy protection criteria.
- Differences in criteria interpretation and application
- Problems with CP application

1:30 - 3:00

April 8-12, 2001 Banff 2001 Pipeline Workshop Slide 9

Corrosion Field Measurement and Growth Modelling

- Corrosion growth modelling update
  - limitations, accuracy, success of present models
  - Review of year 2000 field validations
- Recent developments in external corrosion mapping techniques
  - ease of application, accuracy, correlation to ILI data.

3:30 - 5:00

April 8-12, 2001 Banff 2001 Pipeline Workshop Slide 10

Expectations

- No Judgement or Criticism passed
- Difference of Opinion is OK
- Different Circumstances
  = Different Approaches
- Share, Learn, Have Fun
- Don't take this TOO seriously!

April 8-12, 2001 Banff 2001 Pipeline Workshop Slide 11

Promote teamwork within the working group

Together
Everyone
Achieves
More

April 8-12, 2001 Banff 2001 Pipeline Workshop Slide 12

Promote teamwork within the working group

- Identify and capitalize on diverse skills and experience
- Maximize sharing of experience and questions
- Encourage participation to insure common understanding
- Here to learn *NOT* judge

April 9-12, 2001 Banff 2001 Pipeline Workshop Slide 13

We want YOUR Participation!

BANFF/2001
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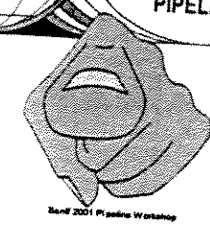

April 9-12, 2001 Banff 2001 Pipeline Workshop

Ground Rules

- Participation of everyone is encouraged
- Listen with understanding
- Stay with the Agenda
- Honour the time limits
- One speaker at a time
- Don't dominate the discussion
- Show patience and respect

April 9-12, 2001 Banff 2001 Pipeline Workshop Slide 15

BANFF/2001
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Environmental Impact of Impressed Current CP Groundbeds

Katherine Ikeda-Cameron
Tom Jack
NOVA Research and Technology

April 9-12, 2001 Banff 2001 Pipeline Workshop

Environmental Impact of Impressed Current CP Groundbeds

- The significance of soil contamination caused by impressed current groundbed operation
- Possible ramifications to the corrosion control industry

April 9-12, 2001 Banff 2001 Pipeline Workshop Slide 17

LUNCH - Back @ 1:30

April 9-12, 2001 Banff 2001 Pipeline Workshop Slide 18

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Codes and Practices Relating to Cathodic Protection

Bob Gummow
Corrosion Service

April 9-12, 2001 Banff 2001 Pipeline Workshop

Codes and Practices Relating to Cathodic Protection

- Regulations and non-regulatory guidelines
  - CSA Z662, OCC-1, NACE RP-0169, Canadian Electrical Code, CSA C.22.3 No. 6, NACE RP-0177
- Differences in code interpretation and code intention.
- Accepted CP criteria and developments in monitoring technologies intended to satisfy protection criteria.
- Differences in criteria interpretation and application
- Problems with CP application

April 9-12, 2001 Banff 2001 Pipeline Workshop Slide 20

BREAK - Back at 3:30

April 9-12, 2001 Banff 2001 Pipeline Workshop Slide 21

BANFF/2001
PIPELINE WORKSHOP

Corrosion Field Measurement & Growth Modelling

Guy Desjardins, Morrison Scientific
Richard Kania, RTD

April 9-12, 2001 Banff 2001 Pipeline Workshop

Corrosion Field Measurement and Growth Modelling

- Corrosion growth modelling update
  - limitations, accuracy, success of present models
  - Review of year 2000 field validations
- Recent developments in external corrosion mapping techniques
  - ease of application, accuracy, correlation to ILI data.

April 9-12, 2001 Banff 2001 Pipeline Workshop Slide 23

BANFF/2001
PIPELINE WORKSHOP

Working Group 10: External Corrosion

Thank you for Participating!

April 9-12, 2001 Banff 2001 Pipeline Workshop

BANFF/2001 PIPELINE WORKSHOP

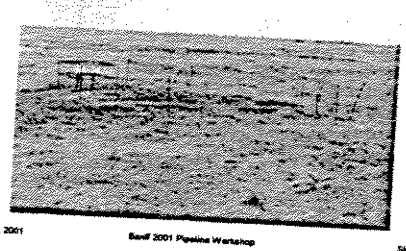
Environmental Impact of Groundbeds

Presentors: Tom Jack & Katherine Ikeda-Cameron
NRTC

April 9-12, 2001 — Banff 2001 Pipeline Workshop

Company Logo Goes Here

THE PROBLEM - Deep Anodes Spit Up!



April 9-12, 2001 — Banff 2001 Pipeline Workshop — Slide 2

Deep Anode Discharge - Dead Vegetation and Landowner Concern

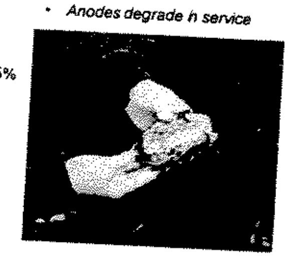
- Natural gas venting through the well brings acidic solution up from the anode
- The solution spills on the ground and kills vegetation
- Soil Sample analysis showed
  - pH 2.8 to 6.3
  - Trace metals
    e.g. Cr, Cu, Ni, V, Zn
    - Near background levels
    - Within guidelines

But what happens underground?

April 9-12, 2001 — Banff 2001 Pipeline Workshop — Slide 3

What is Happening Underground?

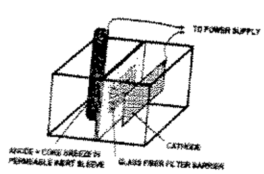
- Anode Specification
  - Silicon, 13.5 to 15.5%
  - Chromium, 4.0 to 5.0%
  - Manganese, 0.5 to 0.85%
  - Iron, balance
- Coke Specification
  - Carbon, 92%
  - Sulfur, 5%
  - Ash, 2.5%
  - Volatiles negligible (petroleum coke)
- *Anodes degrade in service*



April 9-12, 2001 — Banff 2001 Pipeline Workshop — Slide 4

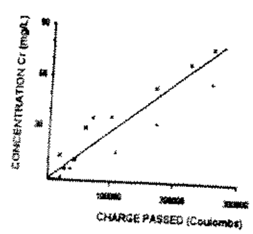
A Laboratory Model Showed *What is Released and at What Rate?*

- Water oxidation accounts for 96% of the electrons flowing through the model anode
  - pH falls to 1 - 2 in the anode compartment
- Metal oxidation releases soluble ions into solution
  - rates of release were determined as a function of Coulombs of charge passed through the anode



April 9-12, 2001 — Banff 2001 Pipeline Workshop — Slide 5

Oxidation at the Anode Releases Soluble Metals in the Lab Model

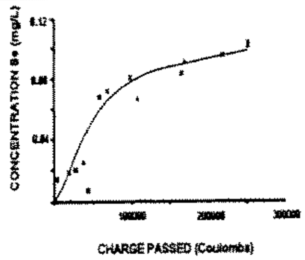


The concentration of soluble metal ions that build up in the closed anode compartment is a function of the charge passed through the anode for metals such as
- Co, Cr, Cu, Mo, Ni

April 9-12, 2001 — Banff 2001 Pipeline Workshop — Slide 6

Oxidation at the Anode Releases Soluble Metals in the Lab Model

For some metals a solubility limit is reached even in the very acidic solution of the anode chamber, e.g.
- B, Fe, Mn, Se, V



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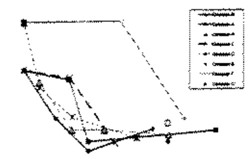
Field Monitoring and Excavations

- Three shallow anode beds were investigated
  - monitoring wells installed around a new operaing anode bed showed no contamination after 11 months operation
  - stagnant water in one old anode bed matched lab solutions
  - soil sampling showed metals had precipitated close to the anode
- e.g. - Chromium



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Solutions and Actions

- Deep anode bedsin susceptible areas have been modified to prevent liquid release to the surface
- Water movement and soluble metal migration will be monitored and modeled at depth around ashallow groundbed to confirm that groundwater contamination is not an issue

Is this enough?

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Acknowledgements

Key participants in this work;
- Mark Blundell
- Robert Worthingham
- Ross McGruther
- Dan Kearney

- Field, lab and professional staff from several Calgary based Technical Consulting and Analytical companies

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Review of Cathodic Protection Codes & Standards

Banff / 2001
Pipeline Workshop
April 2001

R.A. Gummow, P.Eng.
CORRENG Consulting Service Inc.

CSA – Z662-94 Oil and Gas Pipeline Systems

Section 9.2 External Corrosion Control of Buried or Submerged Pipeline Systems

- Cathodic protection must be applied to new piping "as soon as practicable, but not later than one year after installation and shall be maintained during the useful life of the piping" [9.2.1.2]
- Cathodic protection "shall be provided and maintained on existing coated piping" [9.2.2]
- For existing bare piping where a corrosion investigation indicates "corrosion will create a hazard, corrosion control measures or other remedial action shall be undertaken" [9.2.3]
- "Cathodic protection shall be maintained on piping that is out of service but not abandoned" [9.2.4]

Section 9.2.10 Cathodic Protection Systems

- "Cathodic protection systems shall provide sufficient current to satisfy the selected critéria for cathodic protection"

  ("Note: Criteria are given in Appendix 'B' of CGA Recommended Practice OCC-1")

CGA-OCC-1-1996 – Recommended Practice for the Control of External Corrosion on Buried or Submerged Metallic Piping Systems – Canadian Gas Association

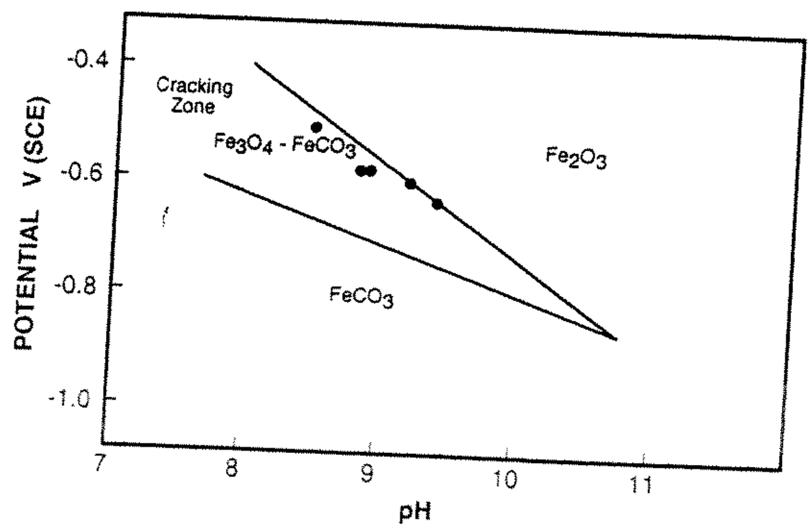
Section B.2.1 Criteria *(Note this is an Appendix)*

- A negative polarized potential ('instant-off') potential of at least 850mVcse.

- A negative polarized ('on') potential of at least 850mV accounting for the voltage drops listed in subsection B.3.

- A minimum of 100mV of cathodic polarization between the structure and a reference electrode contacting the electrolyte as measured by the formation or decay of polarization.

Note: Where steel piping systems are susceptible to stress corrosion cracking (SCC) caution is advised against selecting polarized potentials more electropositive than -770mVcse when using the 100mV polarization criteria.



Comparison of the Results from Stress Corrosion Tests (Continuous Lines) with those from Polarization Curves at Fast and Slow Potential Sweep Rates for Different Carbonate-bicarbonate Solutions, indicating the Extent to which the Experimentally Observed Cracking Range can be Predicted from Electrochemical Measurements

Source: Parkins, R.N. and Fessler, R.R., "Line Pipe Stress Corrosion Cracking – Mechanisms & Remedies", NACE Corrosion '86, Paper No. 320.

NACE RP0169-96 – Recommended Practice Control of External Corrosion on Underground or Submerged Metallic Piping Systems

Criteria – Section 6

- A negative polarized potential of at least 850mV relative to a copper/copper sulfate reference electrode. [6.2.2.1.2]

- A negative (cathodic) potential of at least 850mV with the cathodic protection applied. This potential is measured with respect to a saturated copper/copper sulfate reference electrode contacting the electrolyte. Voltage drops other than those across the structure-to-electrolyte boundary must be considered for valid interpretation of this voltage measurement. [6.2.2.1.1]

- A minimum of 100mV of cathodic polarization between the structure and a stable reference electrode contacting the electrolyte. The formation or decay of polarization can be measured to satisfy this criterion. [6.2.2.1.3]

VOLTAGE IR DROP

[redacted]

OCC-1-1996

The following factors shall be accounted for when interpreting potential measurements for compliance to the criteria listed in Section B.2

a) Voltage (IR) drop between the structure and the reference electrode

b) IR drop in the pipe steel and the lead wire during close interval surveys

c) the presence of dissimilar metals

d) the influence of other structures

e) the presence of stray and telluric currents

[redacted]

NACE RP0169-96

Consideration (*for voltage drop*) is understood to mean the application of sound engineering practice in determining the significance of voltage drops by methods such as:

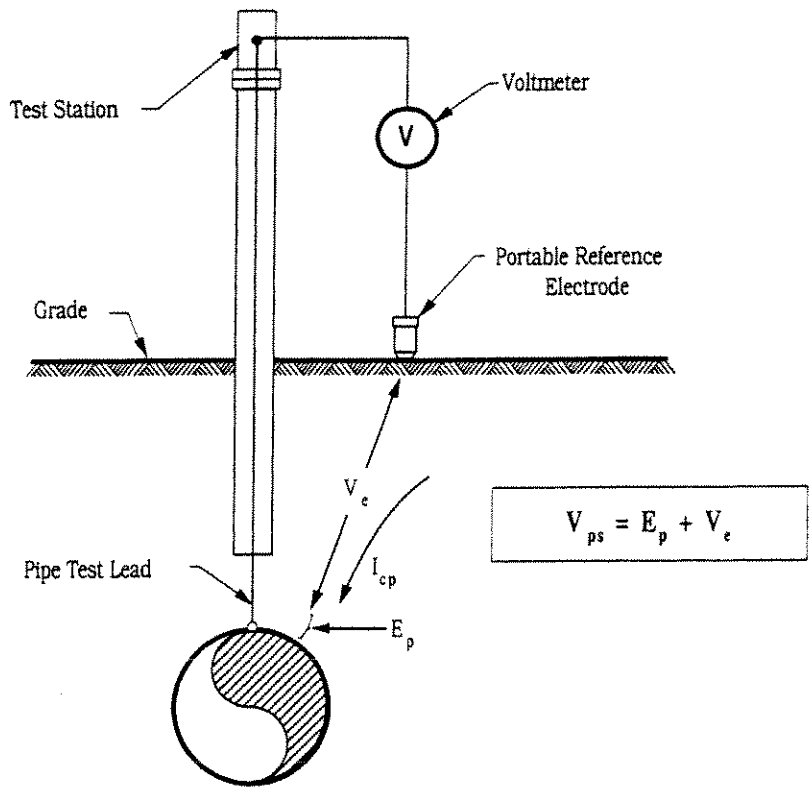
a) measuring or calculating the voltage drop(s);

b) reviewing the historical performance of the cathodic protection system;

c) evaluating the physical and electrical characteristics of the pipe and its environment, and;

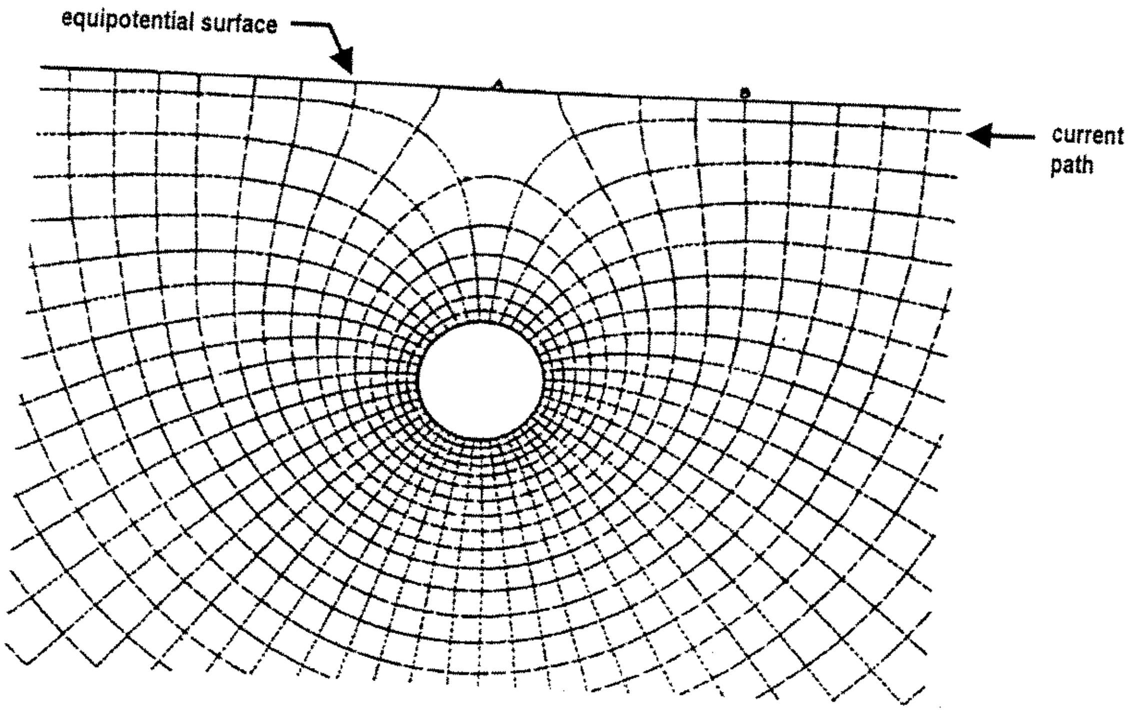
d) determining whether or not there is physical evidence of corrosion.

SOIL IR DROP



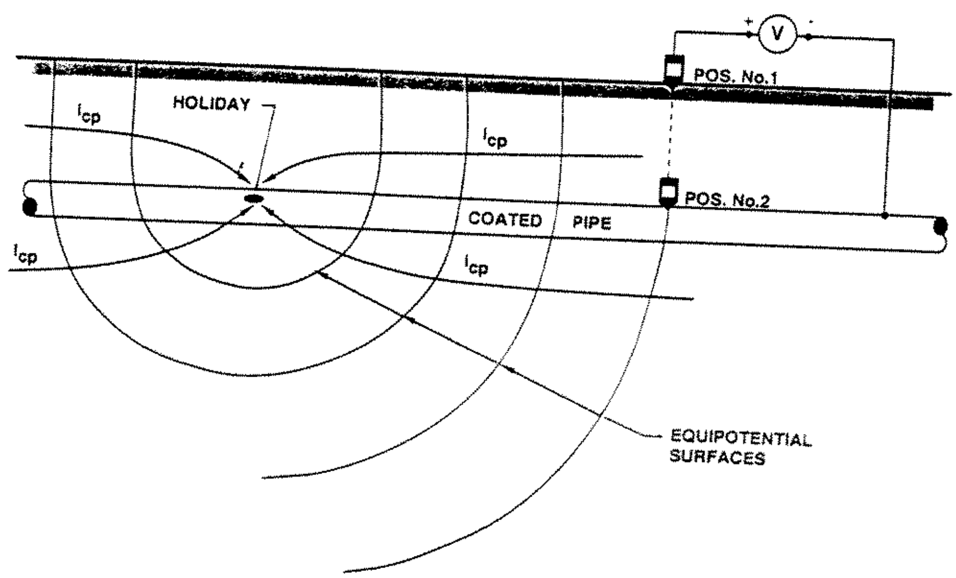
Typical Pipe-to-Soil Potential Measurment

SOIL IR DROP



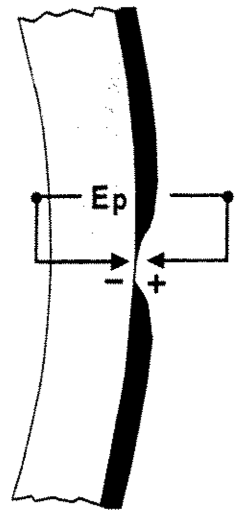
Equipotential Lines and Cathodic Protection Current Paths Around a Bare Pipe

Source: *Parker, Marshall, E., "Pipe Line Corrosion and Cathodic Protection. Publishing, Houston, TX, 1954, p. 16*



Representation of Current Flow to a Holiday in a Coated Pipe

SOIL IR DROP



$$E_p = E_{corr} + \Delta E_p$$

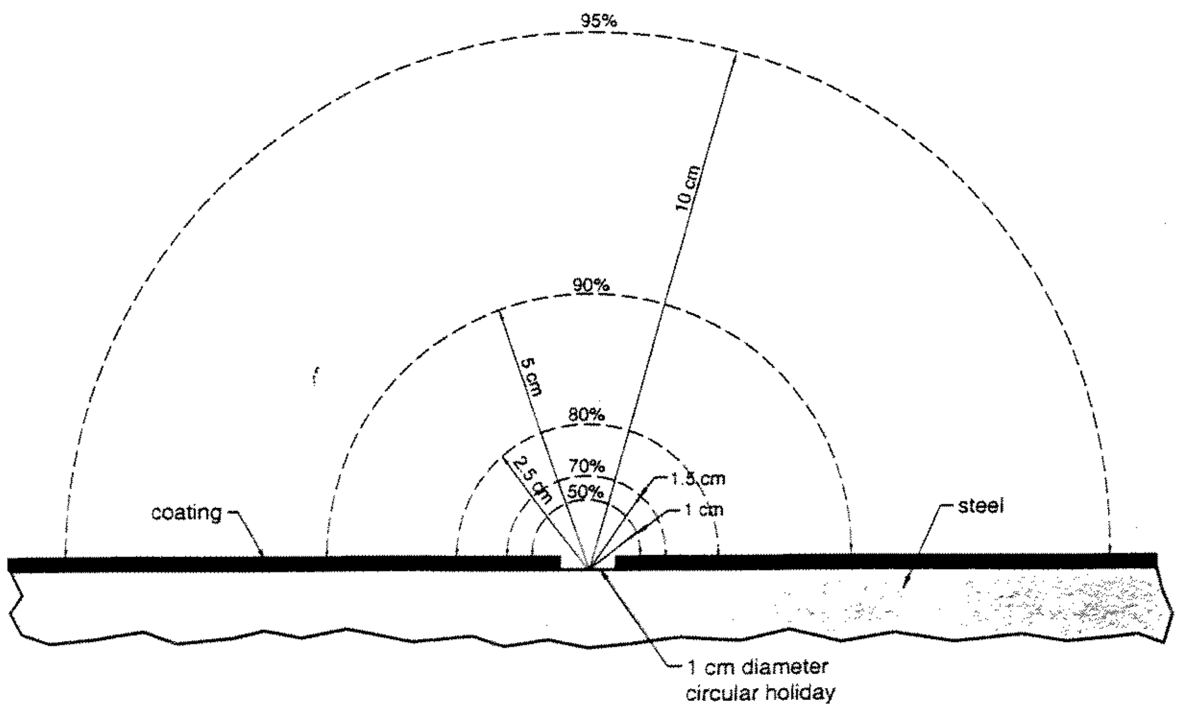
where:

E_p = polarized potential

E_{corr} = corrosion potential

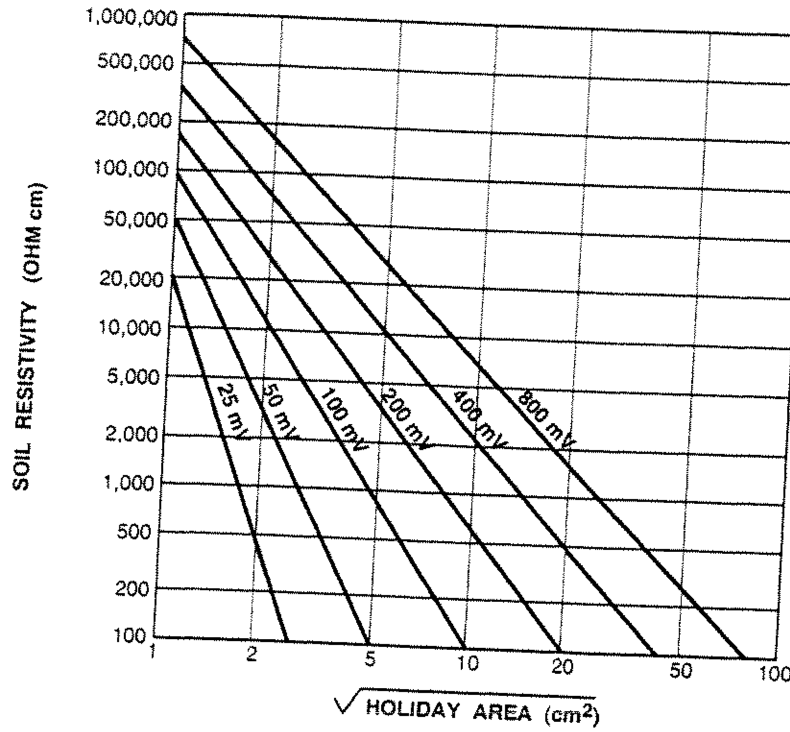
ΔE_p = change in potential due to polarization

Cathodic Polarization at a Coating Holiday



Percentage of Soil Voltage Drop with Distance Away from a Holiday

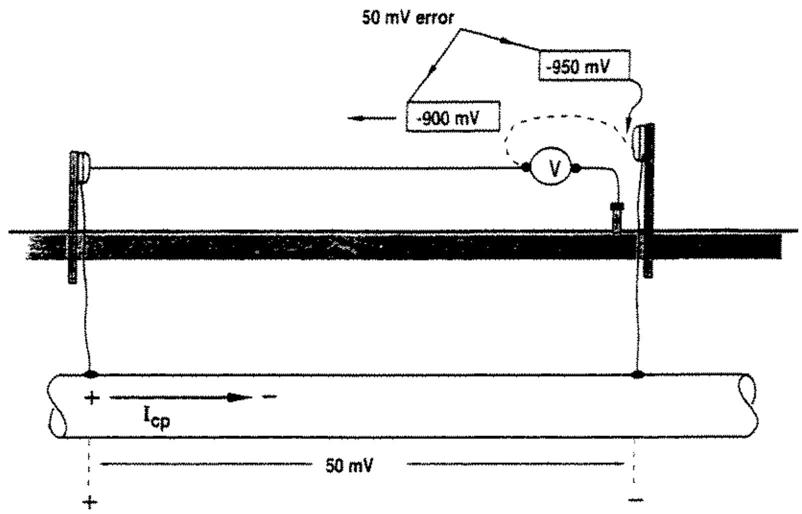
SOIL IR DROP



IR Voltage Drop Relationship to Soil Resistivity and Area of Coating Holiday

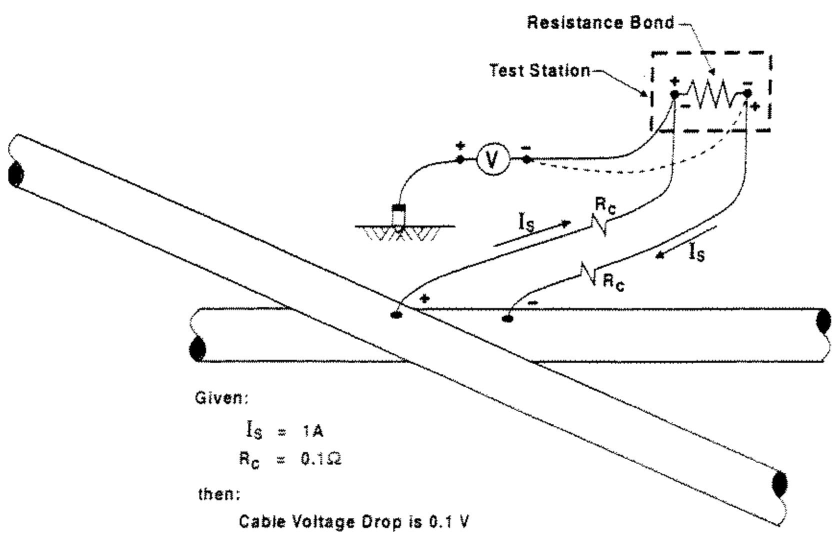
Source: McCoy, John, "Cathodic Protection on the Dampier to Perth Pipeline Australia", MP, NACE, Feb. 1989.

PIPE IR DROP



Error in Pipe-to-Soil Potential Measurement Due to Current in Pipe

CABLE IR DROP



Error in Pipe-to-Soil Potential Measurement
Due to Current in Bond Cables

OTHER CONSIDERATIONS

OCC-1-1996 Section B.2.5

- In the presence of sulfides, bacteria, elevated temperature, acid environment and dissimilar metals, the –850mVcse criteria may not be sufficiently electronegative.
- In some environments (concrete, dry or aerated high resistivity soil, etc.) values more electropositive than the –850mVcse criteria may be sufficient.

NACE RP0169-96

- In some situations, such as the presence of sulfides, bacteria, elevated temperature, acid environments, and dissimilar metals the criteria in Section 6.2.2.1 may not be sufficient. [6.2.2.2.2]
- When a pipeline is encased in concrete or buried in dry or aerated high resistivity soil, values less negative than the criteria in Section 6.2.2.1 may be sufficient. [6.2.2.2.3]

OTHER CONSIDERATIONS

German Standard
DIN 30 676 Design and Application of Cathodic Protection of External Surfaces

		Free corrosion potential in the absence of cell formation (guideline value), in V	Protective Potential, in V_{CSE}
Unalloyed and low-alloy ferrous materials	at temperatures below 40 °C	-0.65 to –0.40	-0.85
	at temperatures higher than 60°C	-0.80 to –0.50	-0.95
	in anaerobic media	-0.80 to –0.65	-0.95
	in sandy soils with resistivities greater than 500 Ωm	-0.50 to –0.30	-0.75

CANADIAN ELECTRICAL CODE
Part 1 – Section 80 (CSA Standard C22.1-98)

80-002 Wiring Methods for Direct Current Conductors

(1) DC wiring in non-hazardous areas shall conform to the requirements of Section 12 of this Code except that wiring below ground shall be permitted to be:

(a) Buried at a depth of not less than 450 mm; or

(b) Buried at a depth of not less than 200 mm where installed in raceway or where mechanical protection is provided in accordance with Rule 12-012(3)

(2) DC wiring in hazardous areas shall conform to the requirements of Section 18 and 20.

(3) Notwithstanding Rule 20-004(8), underground dc wiring below a Class I area shall be permitted to be installed in accordance with Subrule (1) provided:

(a) The wiring is in threaded rigid metal conduit where it emerges from the ground; and

(b) The conduit is sealed where it emerges from the ground and at other locations as required by Rule 18-108 or 18-158.

CANADIAN ELECTRICAL CODE
Part 1 – Section 80 (CSA Standard C22.1-98)

80-004 Conductors

(1) Conductors for dc cathodic protection wiring shall be not smaller than No. 12 AWG and shall be suitable for the conditions of use as indicated in Table 19 for the particular location where installed.

(2) Notwithstanding Subrule (1), conductors smaller than No. 12 AWG shall be permitted to be used for instrumentation and reference electrode leads.

80-010 Operating Voltage

When a cathodic protection system has a maximum available voltage of more than 50 V, the voltage difference between any exposed point of the protected system and a point 1 m away on the earth's surface shall not exceed 10 V.

CANADIAN ELECTRICAL CODE
Part 1 – Section 80 (CSA Standard C22.1-98)

80-012 Warning Signs and Drawings

(1) Tanks, pipes, or structures protected by a cathodic protection system shall bear a marking, either on the structure, or on a tag attached to the conductor close to the connection to the structure, warning that the connection is not to be disconnected unless the power source is turned off.

(2) A notice shall be placed in a conspicuous location adjacent to the disconnecting means for any electrical apparatus that is connected to the cathodically protected structures advising that the cathodic protection must be turned off before equipment or piping is replaced or modified.

(3) Notwithstanding Subrule (2), in a non-hazardous location the required sign shall be permitted to advise the use of a temporary conductor, sized for the maximum available current, to bypass the location where equipment or piping is to be replaced or modified, as an alternative to turning off the cathodic protection.

(4) A drawing showing the location of underground wiring, polarity, and anodes shall be provided inside the rectifier cabinet or in a location near the cabinet.

(5) When the immersed surfaces of a storage or process container are cathodically protected, a notice shall be placed in a conspicuous location adjacent to the entrance way advising that the cathodic protection system must be turned off before entering the container.

CANADIAN ELECTRICAL CODE
Part 1 – Section 80 (CSA Standard C22.1-98)

Table 53 – Minimum Cover Requirements for Direct Buried Conductors, Cables or Raceways

Wiring Method	Minimum Cover - Millimetres			
	Non-vehicular Areas		Vehicular Areas	
	750V or Less	Over 750V	750V or Less	Over 750V
Conductors or cable not having a metal sheath or armour	600	750	900	1000
Conductor or cables having a metal sheath or armour	450	750	600	100
Raceway	450	750	600	1000

Note: Minimum cover means the distance between the top surface of the conductor, cable or raceway and the finished grade.

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Corrosion Growth Modelling

Guy Desjardins, Morrison Scientific

Why Measure Corrosion Rate

- If we knew where corrosion was active, we could go to those sites and fix the problem
- If we knew how fast corrosion was occuring, we would know when to inspect the pipeline

How to Measure Corrosion Rates

- Single in-line inspection
- Multiple in-line inspection
- Failure and repair history of the pipeline
- From similar pipelines in similar environments (especially a parallel pipeline)

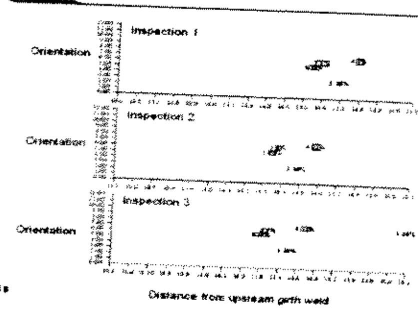
What do you do with corrosion rate information

- Locate sites where corrosion is active so that coating, interference, slope stability, or other issues can be addressed
- Predict future corrosion severity
- Assess the need for future inspections of the pipeline

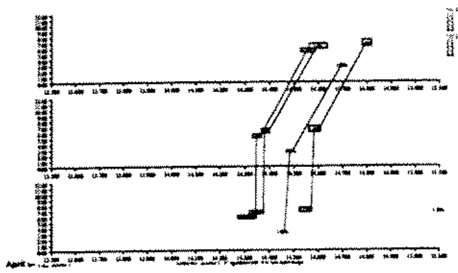
Matching the defects between inspections

- Matching defects between two inspection needs to account for all of the complications from corrosion growth and repair history of the pipeline.
- Other complications include: odometer slippage; orientation differences; limited ILI accuracy measurements of depth, length, and width.
- Changing resolution of ILI tools.
- Sheer number of defect can be large.

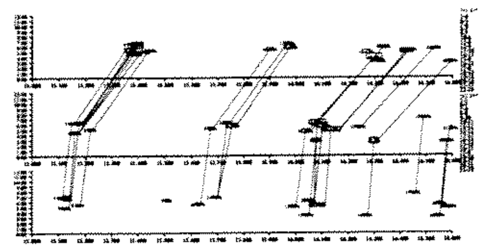
Odometer Slippage



Matches from Inspection 1 to 2 to 3



More Matches



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Determining Corrosion Rate

- The corrosion rate is calculated based on the change in defect size between two or more inspection.
- Limited ILI accuracy complicates the process.
- Corrosion rate must be positive.

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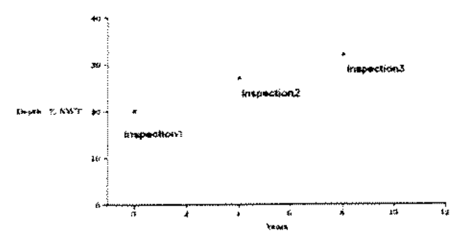
Historical Change in Reported Depth



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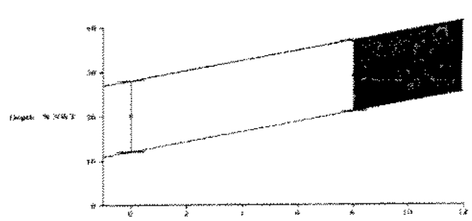
Probable Corrosion Rates



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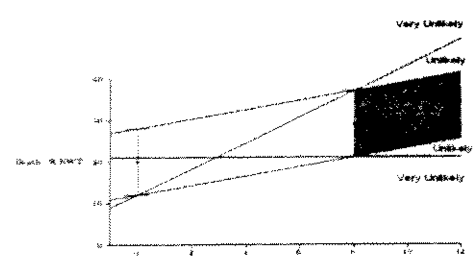
Full Range of Prediction



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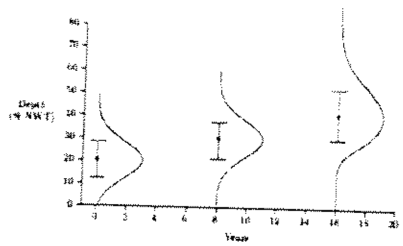
Severity Prediction with Normal Error



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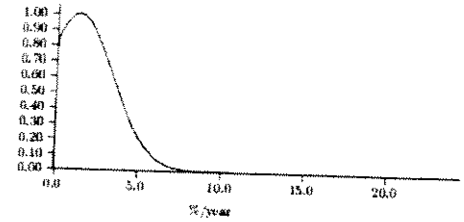
Corrosion Rate Distribution with Normal Error



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Failure Pressure Analysis

- Calculation may be based on
  - B31G
  - modified B31G
  - Iterative Effective Area calculation (like RStreng)
- Defect-interaction rules are used to make cluster defects.
- All pressure calculations are a function of defect length and depth.
  - Accuracy of the measurements of length and depth affect accuracy of the failure pressure calculation

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How does accuracy of length and depth measurements affect the failure pressure calculation?

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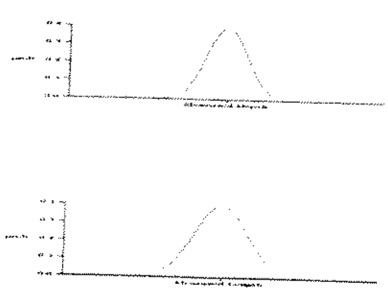
Accuracy of Depth and Length Measurement



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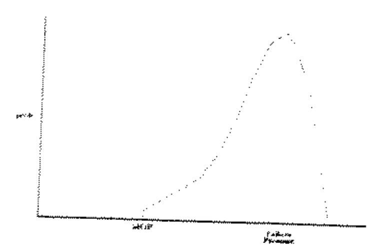
Accuracy of Failure Pressure Calculation



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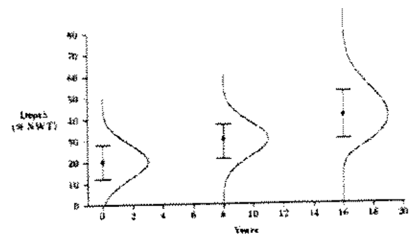
Guy Desjardins, Morrison Scientific Inc.

Recall the Probability Distribution for Predicted Depth



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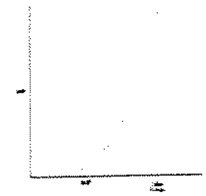
Probability of failure

- The probability distribution in depth leads to a probability distribution of failure pressure
- Probability of failure is the probability that a defect either ruptures or leaks.
- The probability of rupture is the area under the failure pressure probability curve to the left of MOP.



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Depth, Length, Failure Pressure, Corrosion Rate, and Probability of Failure

- Corrosion causes the defect depth and length to increase. Their probability distributions migrate to the left.
- The failure pressure decrease. Its probability distribution migrates to the right.
- The probability of failure increases with time due to corrosion.

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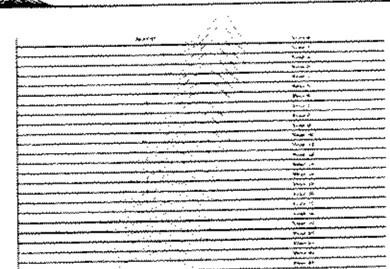
Shifting Failure Pressure Distributions



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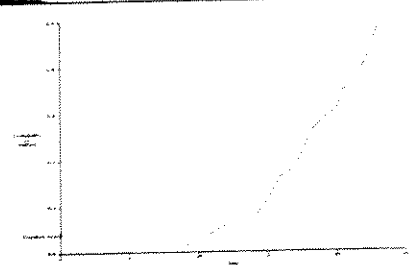
Increasing Probability of Failure



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Penetration			
80% Confidence Intervals for Error Components			
ILI	Growth Methodology	Total Prediction	No. Features
± 13.8%	Triplet ± 10.3%	± 17.2%	113
± 13.8%	Doublet ± 17.6%	± 22.4%	265

Table 2. 1999 DIG PROGRAM. ERROR DISTRIBUTION FOR COMBINATION OF ILI AND PREDICTION ERROR

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Laser-Based Corrosion Mapping System for Pipelines

Richard Kania, RTD Quality Services Inc.

Banff 2001

Data Collection

- Difficulty in providing accurate corrosion representation and measurements from the field to the head office.
- Circumstances of particular excavation.
  - Limited pressure reduction period, limited time to perform inspection
  - Corrosion at 6 o'clock difficult to map, for example.

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Inspection Challenges

- Limited time available for inspection
- Pipes are not straight or round! Able to accurately map corrosion in the presence of welds and surface deformations (suck down, side and over bends, bulges).
- Accurate data required for assessment

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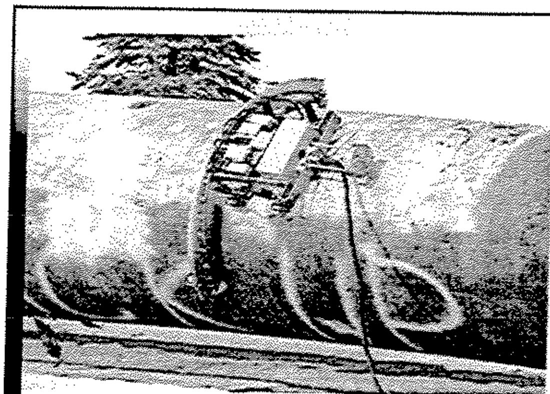

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LPIT Specification Highlights

- Software with built-in RSTRENG module for quick data assessment in the field.
- Depth measurement resolution: +/- 1.5% of Wall Thickness (80% of the time).
- Digital imaging and reporting.

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Testing and Evaluation

Comparison of LPIT, Pit Gage and Ultrasonic Pencil Probe mapping.

Test specimen:

- 5 ft^2 of 20" Diameter pipe inspected by all three methods. Corrosion present in approximately 18% of mapped area.

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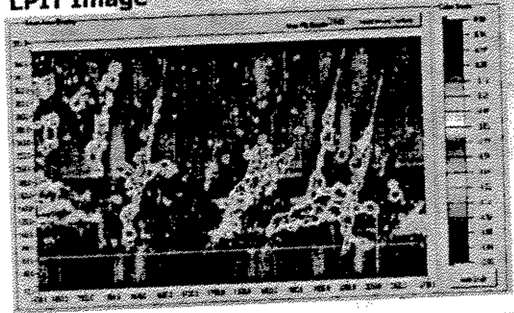
Testing and Evaluation

LPIT Image



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Testing and Evaluation

Goal

Compare time of inspection including setup, scanning/mapping, data processing, accuracy and analysis including corrosion assessment.

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Testing and Evaluation

Results

Setup, inspection, and assessment time combined.

1. Laser 1.2 hrs
2. Pit Gauge 3.1 hrs
3. Pen Probe 4.3 hrs

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Testing and Evaluation

Results

Maximum pit depth comparison

Defect #	Laser	Pit Gauge	Pen Probe
1	1.80	1.7	1.4
2	3.28	3.2	3.0
3	3.76	3.8	3.4
4	2.34	2.4	1.9
5	3.18	4.0	3.1

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Testing and Evaluation

Conclusions following the tests:

- Inspection and data assessment time is substantially lower for laser system
- Confirming the deepest pits is difficult when using manual techniques – raises questions about data accuracy and quality. Need for accurate corrosion measurement techniques.

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Applications

- Corrosion measurement and assessment during excavation projects
- ILI verification/correlation
- Corrosion growth modeling
- Assessment using FEA

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Richard Kania, **RTD Quality Services Inc.**

Managing Pipeline Integrity: External Corrosion
April 10, 2001 10:30 a.m. - 3:00 p.m.

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21	Global Thermoelectric	Garner Mestorus	(403) 204-6163	garnerm@globalte.com	
22	Alliance Pipeline	Terri Johnston	403 517-7701	johnstt@alliance-pipeline.com	
23	Global Thermo.	Coral Lukaniuk	403 204 6174	lukaniukc@globalte.com	
24	TransCanada PL (TNT)	Siu Tsai	403 580-8316	siu_tsai@transcanada.com	
25	Morrison Scientific	Guy Desjardins	(403) 262-8160	guy@morrison-scientific.com	
26	PII	Mohammed Jaweed	(403) 298-[illegible]34	jaweedm@PII-canada.com	
27	PROACTIVE TECH. Inc.	JASPER PRICE	(403) 262-7885	ptii@proactive.ca	
28	HEMPEL COATINGS	JACQUES EBERLE	(604) 273-3200	sales.ca@hempel.com	
29	HEMPEL COATINGS	BERNIE JACOBSON	(780) 457-4111	jacobson@icrossroads.com	
30	ENBRIDGE PIPELINES	DEB BILLEY	(780) 420 5383	deb.billey@cnpl.enbridge.com	
31	ENBRIDGE PIPELINES Inc.	DON ENGEN	(780) 420-8715	don.engen@cnpl.enbridge.com	
32	Integrity Assessment Group	Gerald Baccari	(403) 296-3298	jbaccari@IAGROUP.com	
33	MARR ASSOCIATES	MARK JOHNSON	403 258 2233	mjohnson@marr-associates.com	
34	Corrosion Service Comp Ltd.	Alex Petrusev	403-233-2601	apetrusev@corrosionservice.com	

35	CANSPEC GROUP INC	DAVID JOLIVETTE	780-490-2550	djolivette@canspec.com	
36	NATIONAL Energy Board	Rima Raad	403.299.3624	rraad@neb.gc.ca	
37	National Energy Board	Nancy Dubois	(403) 299-3101	ndubois@neb.gc.ca	
38	PII CANADA Ltd	BRIAN FRANKS	(403) 298-0226	franksb@pii-canada.com	
39	TOM WEBER	TRENTON Corp.	(281) 556-1000	TRENTONHOU@AOL.COM	
40	SOLOMOU COATINGS	THOMAS WRIGHT	(780) 4134545	THOMAS@SOLOMOUCOATINGS.com	
41	DuPont Canada Inc	Jamie Cox	(403) 2546145	Jamie.Cox@can.dupont.com	
42	CORRPRO CANADA, Inc	Grant Firth	(780) 447-4565	grant.firth@corrpro.ca	
43	AEC Oil & Gas	Chris Horkoff	(403) 509-3382	chrishorkoff@aec.ca	
44	HUNTER McDONNELL	JOHN CHASE	780 436 4400	JCHASE@HMPSI	
45	Bob Gummow	CORRENG CONSULTING	905-509-2213	bgummow@correng.com	
46	Imperial Oil	Wayne Fell	(403) 237-2472	wayne.fell@esso.ca	
47	CATHOLIC UNIVERSITY OF RIO DE JANEIRO / BRAZIL	IVANI de S. BOTT	55 (21) 5400403	bott@mail2.rdc.puc-rio.br	
48	PII North America, INC	Christine Bubadeau	713-849-6346	christiner@eul.net in_pipe@swbell.net	
49	PII NORTH AMERICA, INC	BRUCE HAGERMAN	713-849-6332	HAGERMANB@PII-USA.COM	
50	Morrison Scientific Inc	Tom Morrison	403-262-8160	tom@morrisonscientific.com	X
51	Hunter Mcdonnell Pipeline Services	Chris Harthell	406-698-3318	chrish@hmpsi.com	

52	Rainbow Pipeline	Barry Martens	780-449-5856	barry_j_martens@email.mobil.com	
53	ENBRIDGE PIPELINES INC	SCOTT IRONSIDE	780 · 420 5267	scott.ironside@cnpl.enbridge.com	
54	IMPERIAL OIL PIPELINES	LORNA HARRON	780-955-6177	lorna.harron@esso.com.	
55	C.C. Technologies	John Beavers	614 761-1214	jbeavers@cctlabs.com	
56	SIMMONS GROUP INC	DON HERMAN	403 541 5308	simmons@cadvision.com	
57	SUNCOR ENERGY MARKETING	BRIAN DENNIS	780 449 2108	BDENNIS@SUNCOR.COM	
58	WILLIAMS ENERGY	CYRIL KARVONEN	403.444.4550	cyril.karvonen@williams.com	
59	Alliance Pipeline	Lorne Carlson	403-517-6303	[illegible]son@alliance-pipeline.com	
60	TransMountain Pipe Line	Kyla Loewen	780-449-5913	kylal@tmpl.ca	
61	Trans Mountain	Shawn McGregor.	250-371-4011	Shawnm@tmpl.ca.	
62	[illegible]	[illegible]	[illegible]	[illegible]	
63	ENBRIDGE	BRAD SMITH	780·420·8607	brad.smith@cnpl.enbridge.com	
64	CANMET	Jenny Been	613-992-4252	jbeen@nrcan.gc.ca	
65	GREENPIPE	NIGEL ALVARES	403-260-6702	nigelalvares@greenpipe.com	
66	Enbridge	Shaun Dawe	780 420-8684	shaun.dawe@cnpl.enbridge.com	
67	Williams Pi[illegible]	Dan Katz	801 584 6911	[illegible]	
68	~~Neil S. Hay~~ KOCH P/L'S CDN.	Neil S. Hay	(403) 716-7670	HAYN@KOCHIND.COM	

69	Westcoast Energy	Jennifer Wong	604-691-5973	jjwong@wei.org	Jennifer Wong
70	[illegible]	[illegible]	403 531-1926	[illegible]	[illegible]
71	Morrison Scientific ~~Brad Carson~~	Brad Carson	403-762-8160	guy@morrisonscientific.com	[illegible]
72	Petroline	Bob Smyth	403 271-8383	RSMYTH@PETROLINE.com	[illegible]
73	Rosen	Bryce Brown	281·925·0280	bbrown@rosen usa.com	[illegible]
74	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
75	BJ Pipeline Services	Jeff Sutherland	403 531-5300	jsutherland@bjservices.ca	J. Sutherland
76	RTD Quality Svcs.	Richard Kania	780-468-3611	rkania@rtdquality.com	[illegible]
77	Sun-Canadian Pipeline	Ian Smith	905-689-6641	ismith@sun-canadian.com	[illegible]
78	Enbridge Pipelines	Carlos Pardo	780-420 8434	Carlos.Pardo@cnpl.enbridge.com	[illegible]
79	Transgas	Curtis Parker	(306)777-9303	cparker@transgas.sk.ca	[illegible]
80	University of Waterloo	Duane Cronin	519-888-4567 x2682	dscronin@engmail.uwaterloo.ca	[illegible]
81	~~Matt~~ Antero Corrosion	Matt Cetiner	403-232 8212	cetiner@home.com	M Cetiner
82	Tri Ocean Engineering Ltd ~~Darron Mazurek~~	Darron Mazurek	403 218-4676	darron.mazurek@tri-ocean.com	D Mazurek
83	PII	Tom Sawyer	713-849-6323	sawyert@pii-usa.com	[illegible]
84	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
85	Dynamic Risk Assessment Systems, Inc.	Glenn Yuen	403 547-8638	glenn.yuen@dynamicrisk.net	[illegible]

86	BC GAS UTILITY LTD	chris Billinton	250-868-4586	cbillinton@bcgas com	
87	Gas Technology Institute	Harvey Haines	847-768-0891	harvey.haines@gastechnology.org	
88	BRUCE DUPUIS	BASELINE TECHNOLOGIES	403 266 3806	bruced@baselinetech.com	
89	Kyle Keith	Foothills Pipe Lines	403 294 4446	kyle.keith@foothillspipe.com	
90	DEREK STOREY	MARR ASSOCIATES	+44 7968952755	dstorey@marr-associates.com	
91	Chris Jungen	BC Gas Utility	250-868-4571	cjungen@bcgas com	
92	BRUNO ORLICZEK	BC GAS	250-862-6525	BORLICZEK@ bcgas com	
93	Trevor MacFarlane	Dynamic Risk	403.547.8638	trevor_macfarlane@dynamicrisk.net	
94	Conoco Canada Limited	Bruce Moore	306 536-7520	bruce.l.moore@[illegible]	
95	~~Josef Kopec~~ NEB	Josef Kopec	(403) 299-3690	jkopec@neb.gc.ca	
96					
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99					
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BANFF/2001
PIPELINE WORKSHOP

Working Group 10: External Corrosion

Bob Worthingham: TransCanada
Trevor Place: Corrosion Service

Environmental Impact of Impressed Current CP Groundbeds

- The significance of soil contamination caused by impressed current groundbed operation
- Possible ramifications to the corrosion control industry

Environmental Impact of Impressed Current CP Groundbeds

- Very localized concentrations, slightly exceeding agricultural soil guidelines, have been observed within the groundbed only
- Is not considered a significant problem
- Additional study should be performed
- Improved discussion within the industry is recommended
- Need identified for consistent construction and abandonment approaches for anode beds in general

Environmental Impact of Impressed Current CP Groundbeds

ACTION ITEM for Banff 2003:
- Recommendations will be made to NACE International and CEPA to commission industry study of the issue
- Recommendation will be made to NACE International to review construction and abandonment practices for anode beds

Codes and Practices Relating to Cathodic Protection

- Regulations and non-regulatory guidelines
  - CSA Z662, OCC-1, NACE RP-0169, Canadian Electrical Code, CSA C.22.3 No. 6, NACE RP-0177
- Differences in code interpretation and code intention.
- Accepted CP criteria and developments in monitoring technologies intended to satisfy protection criteria.
- Differences in criteria interpretation and application
- Problems with CP application

Codes and Practices Relating to Cathodic Protection

- Only first part of agenda completed
- North American and German CP criteria were discussed
- NACE RP0169 is under review this year – changes may be expected
- Prescriptive vs goal oriented regulations were discussed

Codes and Practices Relating to Cathodic Protection

ACTION ITEMS for 2003
- Follow changes to codes – highlight changes
- Discuss AC interference
- Discuss CP monitoring methods

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Corrosion Growth Modelling

- Growth modelling methods continue to be refined
- Accuracy of this technique has been demonstrated
- Growth modelling based on a triplet of ILI data has shown accuracy approaching that of an ILI run

April 9-12, 2001 Banff 2001 Pipeline Workshop Slide 8

Corrosion Growth Modelling

ACTION ITEMS for Banff 2003:
- Continue with technology updates
- Report on any developments in soils models for predicting external corrosion
- Report on efforts to correlate with other GIS data sets
  - ie. Compare ILI and growth data to aboveground CP data

April 9-12, 2001 Banff 2001 Pipeline Workshop Slide 9

Corrosion Field Measurement

- Recent developments in external corrosion mapping techniques
  - ease of application
  - accuracy
  - correlation to ILI data

April 9-12, 2001 Banff 2001 Pipeline Workshop Slide 10

Corrosion Field Measurement

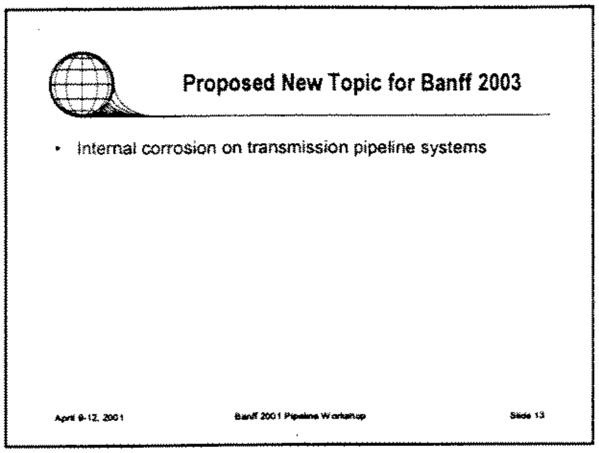
- Laser mapping is a fast and accurate method to assess external corrosion damage
- Provides superior visualization of corrosion features
- Can reduce overall excavation and downtime costs
- Especially suited to large corrosion features

April 9-12, 2001 Banff 2001 Pipeline Workshop Slide 11

Corrosion Field Measurement

- ACTION ITEMS for Banff 2003
  - Technology update

April 9-12, 2001 Banff 2001 Pipeline Workshop Slide 12


Proposed New Topic for Banff 2003
• Internal corrosion on transmission pipeline systems
April 9-12, 2001
Banff 2001 Pipeline Workshop
Slide 13

Workshop 11 – Offshore & Arctic Pipelines: Challenges & Needs

Tuesday, April 10, 2001, at 10:30 a.m.

Chair John Greenslade, Colt Engineering Corporation
Co-Chair Allan Murray Principia Consulting

Opening remarks by John Greenslade indicated that the workshop, and the associated presentations, were to stimulate audience participation with issues specific to northern and offshore pipelines. Further, it was pointed out that the workshop was to be a forum for information exchange and education.

John Greenslade, Colt Engineering Corporation then made a presentation entitled *Offshore & Arctic Pipelines: Challenges & Needs*

- This presentation reviewed issues of strain based design, slope stability, uplift buckling, etc. to stimulate conversation

Q: John Greenslade asked what were the effects of leaving a pipeline on grade as was done in many parts of the world.
A: Jim Oswald suggested that the primary reason for burial of pipelines was to prevent/minimize mechanical damage from external forces.

Q: Larry Dyck indicated that a Geological Survey bulletin existed regarding frost settlement and how much did the large ice content in backfill materials contribute to slope instability
A: Keith Leewis said that slope stability could be monitored with satellite surveys.
A: Allan Murray indicated that any movement vertically or laterally could be identified by satellite but longitudinal movement of the pipeline would not be detected.

Jim Oswald, AMEC Earth & Environment made a presentation entitled *Environmental Challenges of Arctic Gas Pipelines*

- Information presented indicated that the pipeline and right-of-way above the pipeline had subsided to varying degrees over the pipeline operating life and the active zone above the permafrost had increased.
  - the loss of tree cover on the Norman Wells pipeline ROW was believed to have contributed to thawing as solar radiation more readily reached the ground surface.
  - the operating temperature of the pipeline contributed to ground thawing.
- Varying degrees of ditch subsidence existed with different construction techniques

Q: Jasper Price asked when the chilled state of the pipeline ended.
A: Jim Oswald responded that the pipeline was initially required to be chilled to $-1^{\circ}C$ at the Norman Wells discharge. After several years of operation, the requirement was changed to permit the average temperature at Norman Wells to be $-1^{\circ}C$. This meant that the pipeline discharge temperature at Norman Wells may be as high as $-10^{\circ}C$ in the summer or as low as $-4^{\circ}C$ in winter as long as the average temperature remained at $-1^{\circ}C$.

Q: John Greenslade asked if there was any change in the permafrost depth related to the pipeline temperature variations.
A: Jim Oswald indicated that no studies had been done to address this issue.

Q: John Greenslade asked if there was any other effect to the right-of-way or pipeline related to the pipeline temperature variations.
A: Derick Nixon replied that the pipeline at KP2 moved up to 20 cm each season with no detrimental effects indicated for the pipeline.

Q: John Greenslade asked if ditch subsidence in Alaska or elsewhere was an acceptable situation.
A: Dennis Hinnah responded that ditch subsidence in Alaska was aesthetically unacceptable in the last frontier.
A: Derick Nixon replied that with gas pipelines any significant ditch subsidence may allow uplift buckling of the pipe.

- Rick Doblanko advised that uplift had occurred on the Norman Wells pipeline with the cause being temperature variation and not necessarily ditch subsidence. After the integrity of the pipeline was confirmed, the pipe was bermed to ensure protection from the public.

Q: Rick Doblanko asked if anyone had solutions to minimize ΔT on similar pipelines other than his experience of pumping hot air through the pipeline during the backfilling procedure.
A: John Greenslade advised that in some instances operators used double walled pipe with hot water pumped through the annulus to minimize ΔT.

Q: Dave Webster asked if the wood chips used as partial backfill at some slope locations prevented subsidence because of the insulation properties or because the wood chips replaced backfill having high ice content and further whether wood chip rotting was a concern..
A: Jim Oswald indicated that the lack of ice content in the wood chips was the primary reason that ditch subsidence didn't occur. In addition, wood chips had the ability to bridge voids in the backfill that occurred over time. A mixture of hardwood and softwood chips were used and fungicidal decay of the hardwood chips had been an identified problem. This was being dealt with through various handling techniques.

Jack Clark, C-CORE, made a presentation entitled *Offshore Pipeline Design for Ice Scoured Environments*

- The presentation included information on pressure ridge and iceberg scour as well as strudel scour and then dealt briefly with the use of double walled pipe in offshore installations.

Q: John Greenslade asked if there was any specific water depth where strudel scour effects could be ignored as a pipeline design issue.

A: Dennis Hinnah indicated that his experience showed that at water depths of 15 to 20 feet (~5 to 6 metres) the problem could be ignored.

A: Jack Clark responded that if a pipeline was designed to avoid ice scour affects, strudel scour could then be ignored.

Q: Jenny Been asked for information on corrosion/corrosion control issues relating to double walled and offshore pipelines.

A: Dave Webster advised that the external corrosion control techniques used for the outer pipe of a double wall installation and for a conventional single wall pipeline were identical and provided no specific concerns as long as the current density requirements of a particular location were addressed. In the case of a double walled installation, maintaining the integrity of the pipe surfaces in the annular space was of primary concern and this was usually accomplished by displacing the annulus to an inert gas and sealing the annular space to prevent the ingress of water and air.

Q: John Greenslade asked if the use of double walled pipe had any benefit in ice scour locations.

A: Jack Clark indicated that the robust nature of the external pipe was probably a benefit from the point of view of impact damage.

Q: Ian Scott asked what research was underway or need to be done.

A: Jack Clark indicated that more research was required to:

- determine the strength of the ice in pressure ridge scour situations
- to assess the structural response of different pipe grades to scour damage
- to determine the minimum safe depth of burial for a pipeline in a scour zone
- to determine the affect of harmonizing US and Canada codes with respect to strain based design for offshore pipelines

Q: Slade van Rooyen asked if heavy wall pipe would be necessary for arctic construction or only for pressure containment.

A: John Greenslade responded that hydraulics and bending stresses usually dictated the need for heavy wall pipe in a pipeline design, regardless of location.

Environmental Challenges of Arctic Gas Pipelines

Jim Oswell
AMEC Earth & Environmental

Thanks to Enbridge Pipelines (NW) Inc. for permission to use design and performance data.

Issues

- Right-of-Way-Temperatures
- Thaw Settlement
- Slope Performance
- Right-of-Way Drainage and Erosion

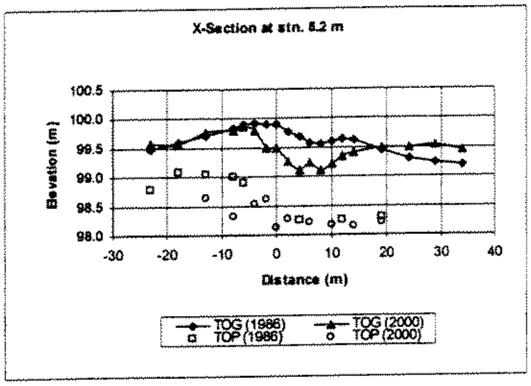
Right-of-Way Temperatures

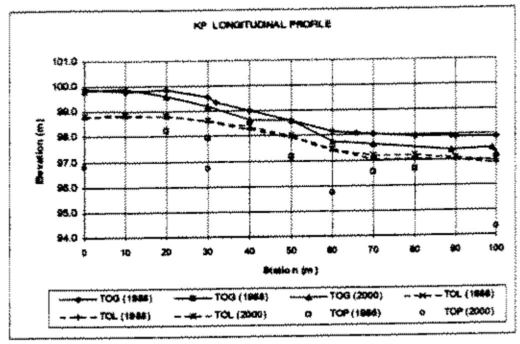
- Significant warming of ground temperatures in early years after construction (some impact due to global warming).
- Pump station influence on line temperatures decrease with distance. In case of Enbridge Pipelines (NW) Inc pipeline, effect is negligible after about 50 km.

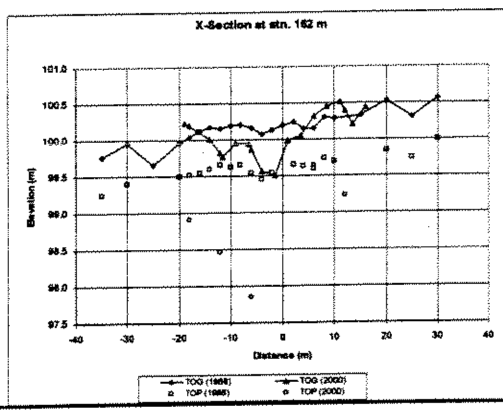
Thaw Settlement

- Design Thaw Settlement
  - 0.8 m in mineral soils for northern region
  - 0.7 to 0.75 m in mineral soils for southern region
  - 1.2 m in high organic soils

Site	Thaw Depth (m) 1996	ROW Settlement (m)	Thaw Strain (%)	Pipe Settlement (m)	Thaw Strain (%)
1	2.75	0.6	21.8	0.35	20
2A	4.5	0.2	4.4		
2B	0.75	0.15	20		
2C	4.5	0.1	2.2		
3A	2.25	0.3	13.3		
7A	4	0.2	21.3	0.2	0.67
7B	5.5	0.5	16.4		
7C	4.25	0.3	7.1	0	0
12B	4.5	1.2	26.7	1.1	31.4
5B	3.25	0.5	15.4	0.5	22.2
6	5.5	0.8	14.5	0.6	12.2
		Average Strain	15%	Average Strain	14 %





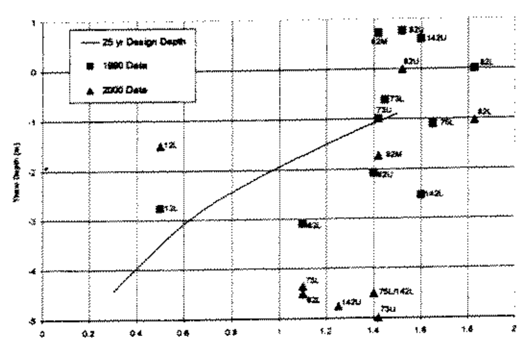


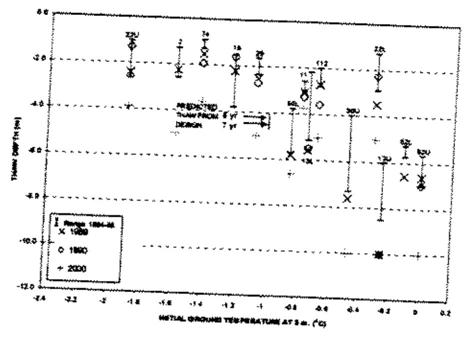
Thaw Performance - Slopes

Frozen and unfrozen slopes
- Approx. 150 slopes
- 37 % have no mitigation measures
- 33 % have select backfill
- 16 % slopes were cut-back
- 46 % insulated
- 8% cut-back and insulated

Thaw Performance - Slopes

- Insulation used was woodchips (gravel was considered but not used).
- Purpose was to retard the rate of thawing.





Physical ROW Condition	1986	1988
No Significant Features	64%	78%
Ditch line Subsidence	29%	15%
Ditch line Subsidence under Woodchip Slopes	0%	1%
Standing Water	1%	2%

Offshore Pipeline Design for Ice Scoured Environments

by

J.I. (Jack) Clark, Ph.D., P.Eng.

Banff/2001 Pipeline Workshop: Managing Pipeline Integrity

April 9-12, 2001

C-CORE

Introduction

- Subsea pipelines to transport oil and gas resources are used extensively in various offshore regions around the world.
- Most performance statistics available are for the Gulf of Mexico where the greatest concentration is found.
- Offshore pipelines can be designed to reliably transport petroleum resources in a safe, environmentally acceptable and cost effective manner.
- Trend in offshore resource development is to deeper water than previously developed and to the Arctic.
- Increasingly harsh environments being developed present unprecedented design, construction and operational issues.
- Pipeline integrity is the paramount issue. Failures are unacceptable in many countries.

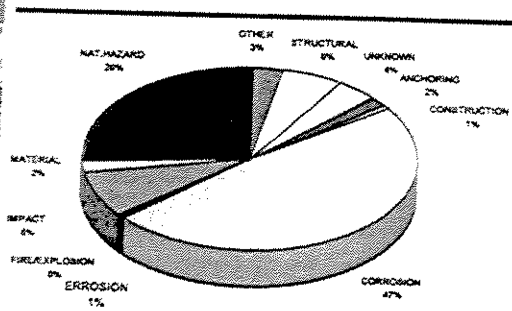
Background

- An estimated 60,000 plus miles of offshore pipelines operating in 2000
- Largest concentration of pipelines is in the Gulf of Mexico - 28,000 miles to 1998
- Largest offshore pipeline 800 km from Sleipner Field (Norway) to Belgium
- Deepest pipeline - Trans Med Project - Tunisia to Italy via Sicily - 2000 ft.
- Only one pipeline of approximately 10 km is operating in northern oceans subjected to ice invasion, ice scour and strudel scour of the seabed (Northstar in Alaska)
- Several thousands of miles of offshore pipelines in ice scoured terrain are under consideration

Performance Records

- Performance records for offshore pipelines in the Gulf of Mexico are comparable to overland pipelines - failure rate is in the range of 1 x 10^{-3} to 10^{-2}
- The factors contributing to failures are different than on land system - third party interventions are lower but still significant. They include, vessels, anchors, fishing trawls, dropped objects etc.

Offshore Pipeline Failure Stats., Bea (1999)



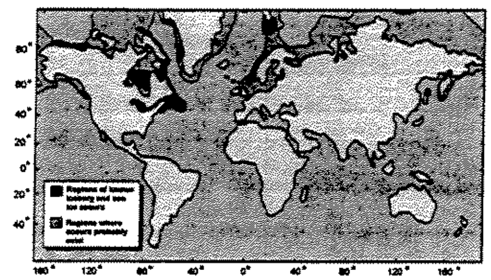
Performance Records (cont'd)

- Failure rates include pipelines built many years ago to less rigorous standards than exist today
  - corrosion can be significantlyreduced if not eliminated by present day coatings
  - materials are much improved - no spiral welds
  - construction techniques improved
  - design requirements set out in codes of practice are much more rigorous today than a decade ago
    - CSA Z662-99 Oil & Gas Onshore and Offshore
    - API RP1111 1999 Offshore Hydrocarbon Liquids & Gases
    - DNV 1996 Offshore Liquid & Gas
    - BS 8010 Liquid & Gas
    - ASME B31-4 1992 Gas Liquids Hydrocarbon
    - ASMI B31-8 1995 Gas
    - US DOT Part 195 Hazardous Liquids

Design Challenges for Arctic Offshore Pipelines

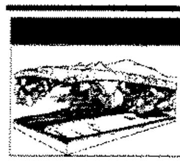
- Ice invasion every year
- Ice scour
- Strudel scour
- Short construction season
- Hostile climate
- Difficult logistics
- Environmental sensitivity

Ice Scour Features Known & Expected



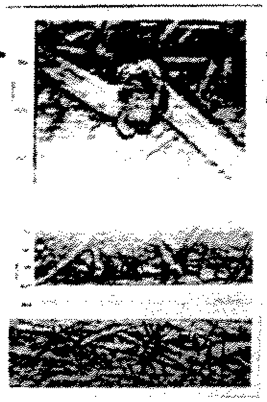
PIPELINES IN ICE ENVIRONMENTS

Ice Scour/Seabed/Pipeline Interaction



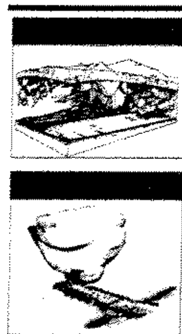
Ridge Characteristics
- Arctic and sub-arctic
- First-year or multi-year ice
- 0m – 30m water depth
- 1km – 2km length
- 0.5km – 1km wide

Iceberg Characteristics
- Arctic and Antarctic
- Canada, Greenland, Alaska
- 5,000 – 10,000 years old
- <180m draught, <250m length
- 100,000 – 2,000,000+ tonnes

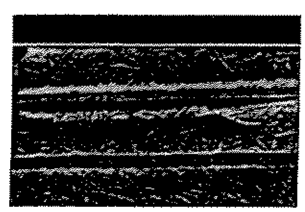


Iceberg Scour Mark

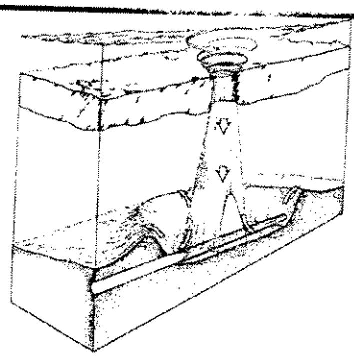
Ice Scour/Seabed/Pipeline Interaction



Limiting Factors
- Environmental driving force
- Ice strength and kinematics
- Soil strength

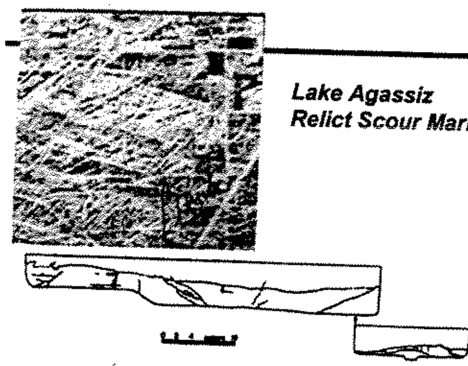


Strudel Scour, Smith (1998)



Background of Research by C-CORE

- Phenomenology
- Field work
- Experimental Modelling
- Engineering Model
- Pipeline Risk Assessment Framework
- Ice/seabed/pipeline interaction
- Applications of Pipeline Risk Assessment



Lake Agassiz Relict Scour Marks

PRISE Participants

ARCO Alaska Inc.
BP Alaska
Chevron
Exxon Production Research Company
Gulf Canada Resources
Marathon Oil
Minerals Management Service (U.S.Dept. of Interior)
Mobil Research and Development Corporation
Mobil Oil Canada Properties
National Energy Board (Canada)
Norwegian Research Council
Petro-Canada
TransCanada Pipeline Ltd.
Union Texas Petroleum

PRISE RESEARCH TEAM

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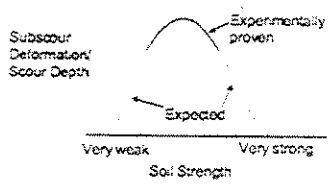
Concordia University (Quebec)
Environmental Science and Engineering, Inc. (Florida)
Geologic Survey of Canada
Nixon Geotech Ltd. (Calgary)
Norwegian Geotechnical Institute (Oslo)
University of Birmingham (England)
University of Laval
US Geologic Survey
Woodward-Clyde Consultants (Florida)



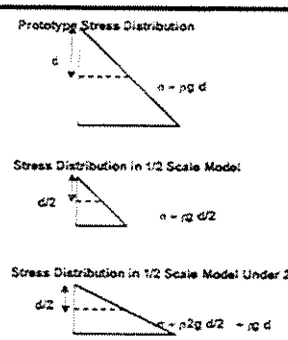
Relative subscour deformation vs soil strength

Ice Scour/Seabed/Pipeline Interaction

Characterization of Subscour Deformation

- Developed by C-CORE under PRISE
- Centrifuge modelling studies
- Empirical equations defining subscour displacement field
- Substantiated by field observations

PRINCIPLE OF CENTRIFUGE MODELLING



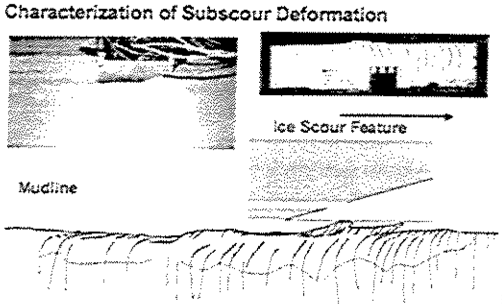
SCALING FACTORS

Mechanical Processes at 100g

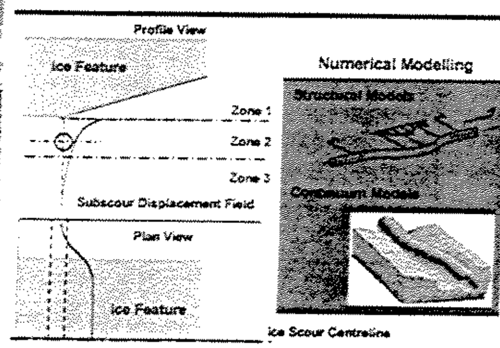
	Full-scale	Model-scale	
Length	100 m	1 m	n
Mass	1,000 tons	1 kg	n^3
Energy	1 ton	1 gm	n^3
Time (diffusion)	27 years	1 day	n^2
Time (inertia)	3.3 months	1 day	n

Ice Scour/Seabed/Pipeline Interaction

Characterization of Subscour Deformation



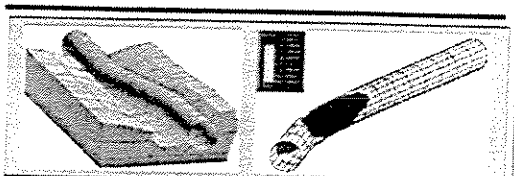
Ice Scour/Seabed/Pipeline Interaction



Numerical Modelling Issues

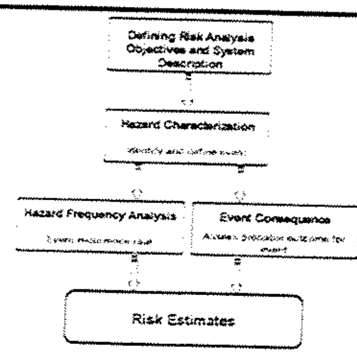
- Pipeline Structural Response
  - Allowable strain limits due to large relative displacements
- Structural Stability – Compressive Limits
  - Serviceability issue
  - D/t ratio, σ–ε response, moment-curvature, pressure
  - Incipient buckling, wrinkling and ovalization
- Structural Integrity – Tensile Limits
  - Containment issue
  - Engineering Critical Assessment (ECA)
  - Material behaviour (CTOD values and HAZ properties)
  - Flaw size, shape and location

Numerical Modelling Issues

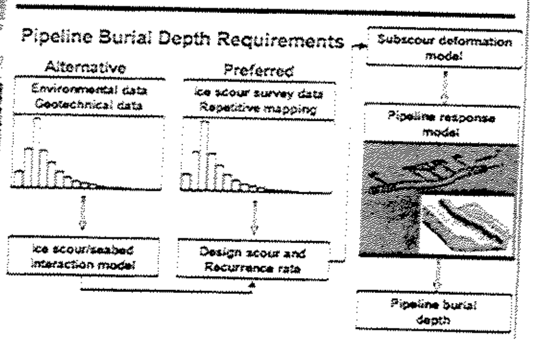


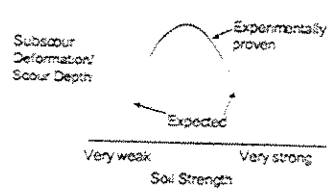
- Continuum Finite Element Analysis
  - State-of-art for coupled ice scour/soil/pipeline analysis
  - Addresses limitations of the structural model
  - Considerable expertise, significant resources
  - Future need to couple with discrete element method, structural finite element models and experimental investigations

Risk Assessment Framework

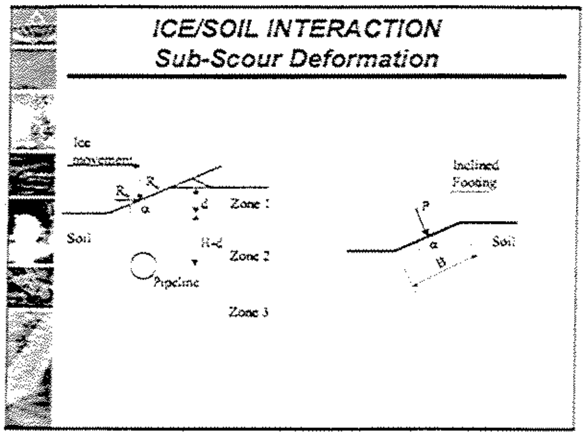


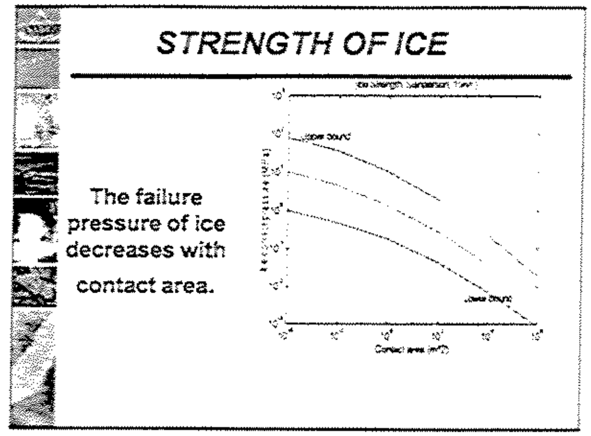
Pipeline Risk Assessment Framework

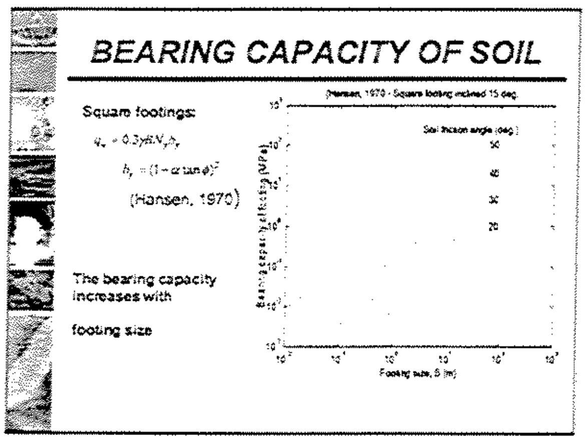


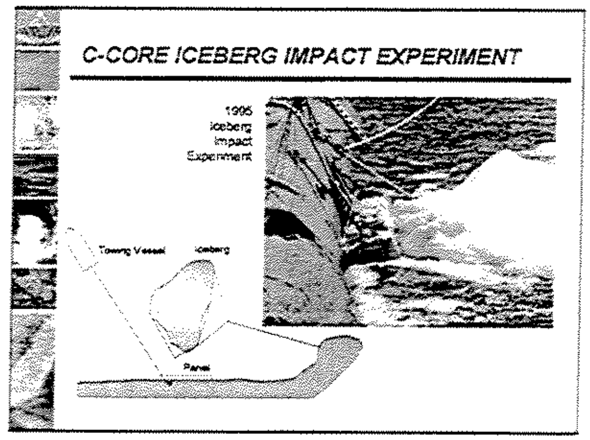


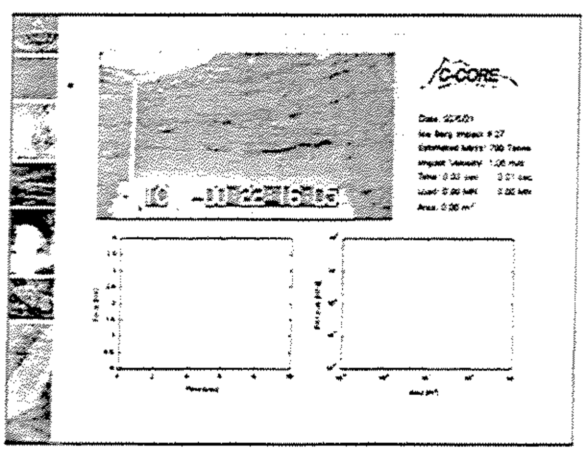
Relative subscour deformation vs soil strength

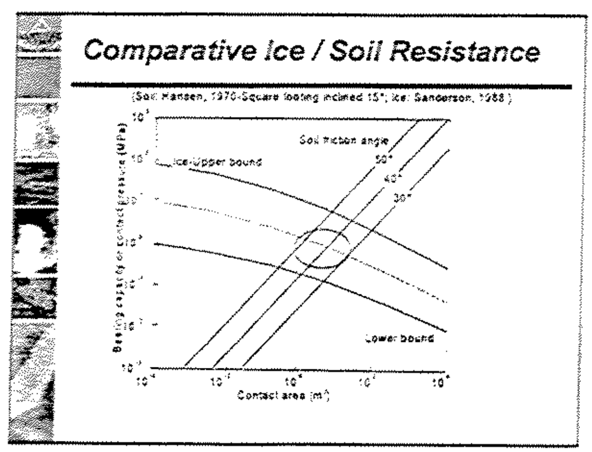

ICE/SOIL INTERACTION
Sub-Scour Deformation
Ice
movement
Zone 1
Soil
Zone 2
Pipeline
Zone 3
Inclined
Footing
Soil


STRENGTH OF ICE
The failure
pressure of ice
decreases with
contact area.
Upper bound
Lower bound
Contact area (m^2)


BEARING CAPACITY OF SOIL
Square footings:
(Hansen, 1970)
The bearing capacity
increases with
footing size
Soil friction angle (deg.)
50
40
30
20
Footing size, B (m)


C-CORE ICEBERG IMPACT EXPERIMENT
1995
Iceberg
Impact
Experiment
Towing Vessel
Iceberg
Panel


C-CORE

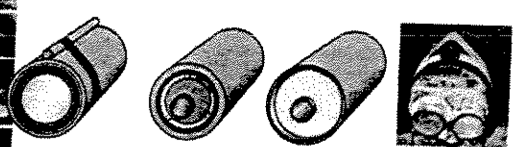

Comparative Ice / Soil Resistance
Soil friction angle
Ice-Upper bound
50°
40°
30°
Lower bound
Contact area (m^2)

Pipe in Pipe Design

Pipe in Pipe

- Insulation to reduce thermal effects
- Containment (no pipe in pipe as yet constructed offshore for containment)
- Approximately 500 miles of pipe in pipe is in service
- Only one known failure during operation (1999)
- Some failures during construction (tow out)

Various Configurations, McBeth (1999)



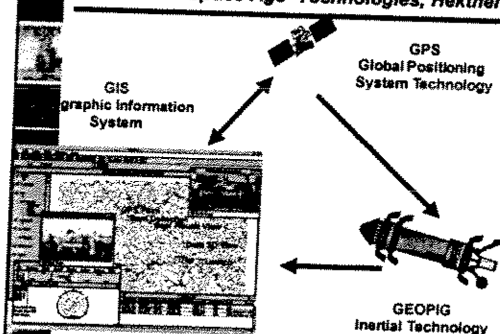
single wall and external bundle

pipe-in-pipe with spacer

pipe-in-pipe with bulkhead

Drake F-76 bundle

Pipeline Mapping and GIS Integration uses Three 'Space Age' Technologies, Hektner (1999)



Design Challenges to Offshore Pipelining

- Design criteria and definitions are not consistent from country to country, e.g. CSA and API
  - Hoop Stress - API. Recommended practice allows over 10% higher internal design pressure than CSA Standard
  - Maximum operating pressure - API and CSA are essentially the same
  - Combined Loads - Combined Stresses
    - The methodologies are based on different combined stress hypothesis. If the longitudinal stress is significant, the allowable maximum operating pressure will be about the same.
    - If longitudinal stress is small then design is governed by Hoop-Stress analysis and API allows a greater stress
  - Hydrostatic Test Pressure
    - Although somewhat different methodologies they provide approximately the same stress limits
  - Strain Limits
    - Major difference

Design Challenges to Offshore Pipelining (cont'd)

- The API recommended practice does not provide for design of pipelines for large strains
- API does not identify a strain limit for continued pipeline operations
- CSA recognizes historic anecdotal evidence of 1% - 2.5% tensile strain limit. Code, however, only allows 0.75% strain. Then x by a factor 0.7 to get an allowable strain limit of ≅ 0.5%.
- The main body of CSA code for offshore pipelines (Chapter II) allows 2.5% less residual. This strain level must be demonstrated.
- CSA identifies a tensile strain limit for the pipewall (elastic and plastic) of 2.5% less residual strain.
- CSA strain limits may be tensile or compressive strain determined by Gresnigt type formula.
- The CSA strain limit includes tensile strains from installation

This is a very significant difference for offshore pipelines in the Arctic that may be subjected to ice scour or strudel scours. API may require removal and replacement when in fact the reliability and service ability are not impaired.

Major Issues

- Harmonization of Design Codes
  - Strain based design
  - Definition of allowable strain limits
- Definition of Failure
  - Functional Defect - pipeline can be operated and inspected by pigging. Repairs can be scheduled - e.g. pop up, wrinkle
  - Functional Failure - pipeline can continue to operate but cannot be pigged. Some flexibility in repair scheduling - e.g. landslide.
  - Containment Failure - loss of product. Pipeline is shut in immediately.

CONTAINMENT FAILURE

A containment failure is defined as pipeline system damage with loss of product containment integrity, that is product loss to the external environment.

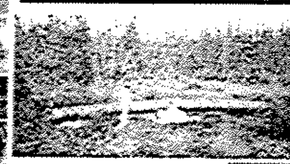
FUNCTIONAL FAILURE

A functional failure is defined as pipeline system damage without loss of product containment integrity to the environment.

[A functional defect, as shown here, is one where the pipe has been damaged but where all operations including inspection can carry on as before.

A functional failure is one where there is no product loss but the configuration will not allow all operations such as pigging or full operational pressure.]

EXAMPLE - FUNCTIONAL DEFECT



Before, (Upheaval Buckling)

After Repair (Gravel cover)

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ARCTIC AND OFFSHORE PIPELINES

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❶ TECHNICAL CHALLENGES

❷ENV IRONMENTAL CHALLENGES

❸ARCTIC OFFSHORE PIPELINES

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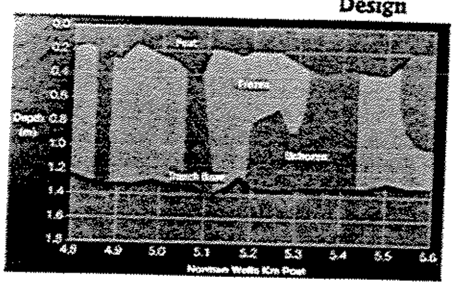
Technical Challenges
Pipelines in Permafrost

Robust Geotechnical Design



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Technical Challenges

Establishing:

- *Strain Limit*
- *Steel Grade*
- *Girth Weld Flaw Acceptance Criteria*

for Pipelines Buried in Permafrost

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Technical Challenges
Pipelines in Permafrost

- Strain Based
- Limit States Design

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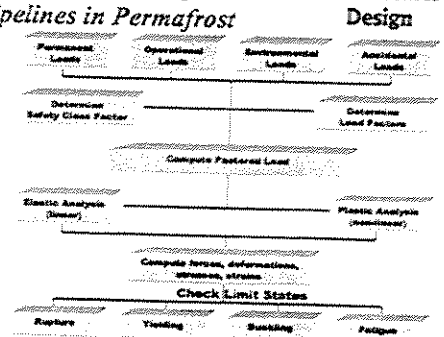
Technical Challenges
Pipelines in Permafrost

Limit States Design



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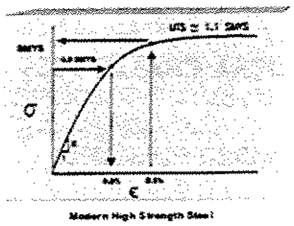
Technical Challenges
Pipelines in Permafrost



- Hoop Stress:
  $\sigma_h \le 0.8$ SMYS
  Load factor = 1.3 for internal pressure
- Combined Stress:
  $\sigma_h + \sigma_L \le 0.9$ SMYS
  Load factor = 1.25 for thermal loads
  Von Mises method, non-linear analysis
- Combined loads that include bending:
  $\sigma_h + \sigma_b + \sigma_L \le$ SMYS
  - Tensile strain limit depends upon:
    - elastic yield strain
    - bending strain
    - CTOD fracture toughness value
    - material properties
    - flaw size, shape, and location
  - Compressive strain limit depends upon:
    - material properties
    - soil properties
    - bending strain
    - axial stress
    - internal pressure
    - over-burden loads
    - section modulus
    - d/t ratio

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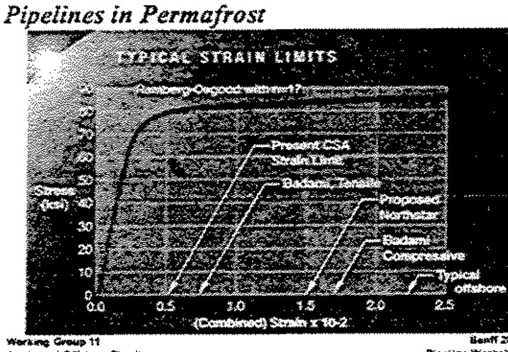
Technical Challenges
Pipelines in Permafrost



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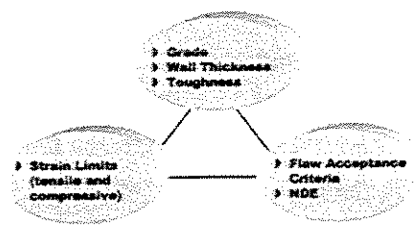
Technical Challenges
Pipelines in Permafrost



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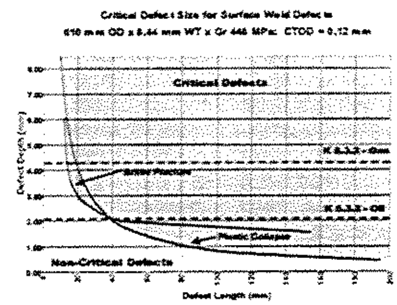
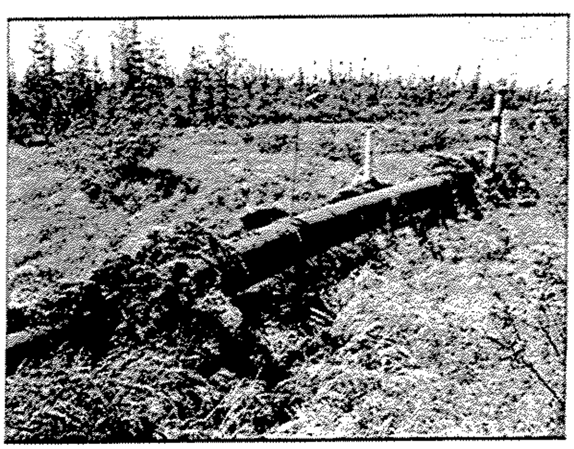
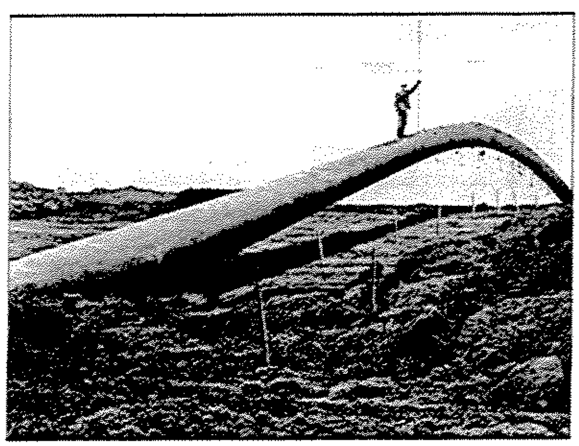
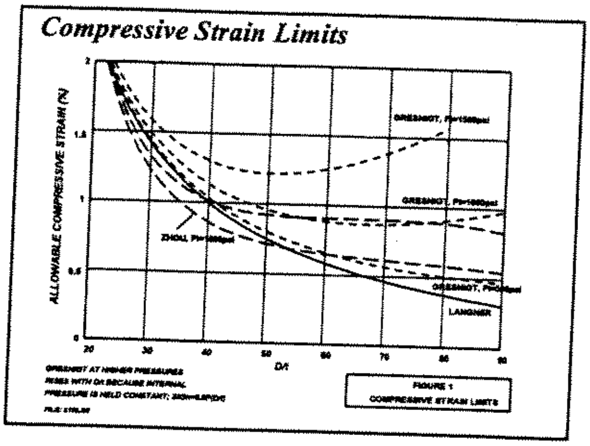
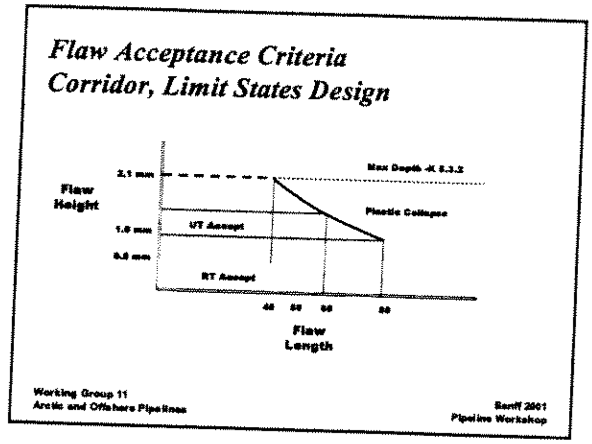
Technical Challenges
Pipelines in Permafrost








Compressive Strain Limits
ALLOWABLE COMPRESSIVE STRAIN (%)
2
1.5
1
0.5
0
20
30
40
50
60
70
80
90
D/t
LANGNER
FIGURE 1
COMPRESSIVE STRAIN LIMITS


Flaw Acceptance Criteria
Corridor, Limit States Design
Flaw
Height
UT Accept
RT Accept
Plastic Collapse
Flaw
Length
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Managing Pipeline Integrity: Offshore & Arctic Pipelines: Challenges & Needs
April 10, 2001 10:30 a.m. - 3:00 p.m.

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4	AMEC	Mike Berezowski	403 235-8135	Mike.Berezowski@Amec.Com	
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6	CAPP	Ian Scott	(403) 267-1132	scott@capp.ca	
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11	NRCan-Canmet	Wenyue Zheng	613 992-7904	wzheng@NRCan.gc.ca	
12	AMEC Earth & Environment	Jim Oswell	403 235 8113	jim.oswell@amec.com	
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14	KOMEX INTERNATIONAL	FRED CLARIDGE	403-247-0200	fclaridge@calgary.komex.com	
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Offshore and Arctic Pipelines

Offshore & Arctic Pipelines: Challenges & Needs - John Greenslade

- Strain Limit
- Steel Grade
- Girth Weld Flaw Acceptance Criteria
- Limit States Design

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Environmental Challenges of Arctic Gas Pipelines - Jim Oswald

- Permafrost
- ROW
- Slope stability
- Pipeline integrity

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Offshore Pipeline Design for Ice Scoured Environments - Jack Clark

- Pressure ridge scour
- Iceberg scour
- Strudel scour
- Double walled pipe

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Offshore & Arctic Pipelines

Conclusions

- Construction issues in permafrost
  - Backfill subsidence
  - Affect on permafrost and ROW vegetation
- Harmonization of US/Canada offshore design codes
- Burial depth for an offshore pipeline in a scour zone
- Design issues
  - *strain based design, slope stability, uplift buckling*

Working Group 11
Offshore & Arctic Pipelines

BANFF 2001 PIPELINE WORKSHOP

Managing Pipeline Integrity: A Workshop for Sharing Technology and Experience

April 9 - 12, 2001

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